BEFORE THE GEORGIA PUBLIC SERVICE COMMISSION

STATE OF GEORGIA

In Re:

Georgia Power Company's 2023 Integrated Resource Plan Update) Docket No. 55378

Hearing Room 110
244 Washington Street
Atlanta, Georgia

Tuesday, January 16, 2024

The above-entitled matter came on for hearing pursuant to Notice at 9:30 a.m.

PRESENT WERE:

JASON SHAW, Chairman
TIM ECHOLS, Vice-Chairman
FITZ JOHNSON, Commissioner
LAUREN "BUBBA" MCDONALD, Commissioner
TRICIA PRIDEMORE, Commissioner

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WITNESSES:	DIRECT	CROSS	REDIRECT	RECROSS
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P R O C E E D I N G S

CHAIRMAN SHAW: All right. Good morning again, everyone. We're going to go ahead and get started.

This is Docket No. 55378: Georgia Power Company's 2022 Integrated Resource Plan Update. We will start by calling for appearances.

Georgia Public Service Commission.

MR. THOMAS: Good morning. Preston Thomas and Ginny Davis on behalf of the Public Interest Advocacy Staff.

CHAIRMAN SHAW: Good morning, Preston. How is the little one?

MR. THOMAS: Good. Not sleeping a lot.

CHAIRMAN SHAW: Georgia Power Company.

MR. HEWITSON: Good morning. Steve Hewitson, Brandon Marzo and Allison Pryor on behalf of Georgia Power Company.

CHAIRMAN SHAW: Good morning.

Advanced Power Alliance.

MR. CARVER: Brad Carver. Hall, Booth, Smith on behalf of the Advanced Power Alliance. Good morning.

CHAIRMAN SHAW: Good morning.

Clean Energy Buyers Association.

MR. DUNBAR: Good morning, Commissioners.

Scott Dunbar of the law firm of Keyes & Fox here on behalf of the Clean Energy Buyers Association.

CHAIRMAN SHAW: Good morning.

Heelstone Renewable Energy, LLC.

MR. GALLOWAY: Good morning, Mr. Chairman. Newton Galloway and Terri Lyndall on behalf of Heelstone. Thank you.

CHAIRMAN SHAW: Georgia Association of Manufacturers.

MR. JONES: Good morning, Mr. Chairman. Clay Jones on behalf of GAM.

CHAIRMAN SHAW: Good morning, Mr. Jones.

Georgia Center for Energy Solutions.

Mr. Hubbard.

(No response.)

CHAIRMAN SHAW: Georgia Center for Energy Solutions.

(No response.)

CHAIRMAN SHAW: Georgia Coalition of Local Governments.

MS. BROWN: Good morning, Commissioners. Alicia Brown on behalf of Georgia Coalition of Local Governments.

CHAIRMAN SHAW: Good morning.

Georgia Interfaith Power & Light.

MS. WHITFIELD: Good morning, Commissioners. Jennifer Whitfield and Bob Sherrier on behalf of Georgia Interfaith Power & Light.

CHAIRMAN SHAW: Georgia Solar Energy Association.

(No response.)

CHAIRMAN SHAW: Georgia Energy Solar Association.

(No response.)

CHAIRMAN SHAW: Georgia WAND Education Fund.

(No response.)

CHAIRMAN SHAW: Georgia WAND Education Fund.

(No response.)

CHAIRMAN SHAW: Georgia Watch.

MS. COYLE: Good morning, Commissioners. Liz Coyle for Georgia Watch.

CHAIRMAN SHAW: Good morning, Liz.

Metropolitan Atlanta Rapid Transit Authority, which I will begin to refer after this as MARTA.

MS. STURM: Yes. Good morning, Commissioners. Kasey Sturm on behalf of MARTA.

CHAIRMAN SHAW: Good morning. Thank you.

Resource Supply Management.

MR. BAKER: Robert Baker on behalf of Resource Supply Management.

CHAIRMAN SHAW: Mr. Baker, good morning.

Sierra Club.

MS. ARIZA: Good morning, Commissioners. Isabella Ariza and Curt Thompson on behalf of Sierra Club.

CHAIRMAN SHAW: Good morning.

Southern Alliance for Clean Energy and Southface Energy Institute.

MR. JACOB: It's Bryan Jacob on behalf of Southern Alliance for Clean Energy. I don't believe Southface is intervening in this docket.

CHAIRMAN SHAW: That must be a typo on our --

MR. JACOB: Well, I heard when you called the docket to order you referred to it as the 2022 IRP Update. I believe when they filed it they called it the 2023 IRP Update. And we did jointly intervene with Southface in the 2022 IRP itself.

CHAIRMAN SHAW: Well, again, there's another typo. We'll get those corrected. I appreciate you bringing those to our attention, Mr. Jacob.

So it's the 2023 Integrated IRP Update.

Southern Renewable Energy Association.

MR. MAHAN: Good morning, Commission. Simon Mahan on behalf of the Southern Renewable Energy Association.

CHAIRMAN SHAW: Good morning.

United States Department of Defense and All Other Federal Executive Agencies.

MR. McNUTT: Good morning, Mr. Chairman. John McNutt on behalf of United States Department of Defense and All Other Federal Executive Agencies.

CHAIRMAN SHAW: Good morning.

Walmart.

MS. EATON: Good morning, Commissioners. My name is Stephanie Eaton. I'm here on behalf of Walmart, Inc. and from the law firm of Spilman Thomas & Battle. Thank you.

CHAIRMAN SHAW: Thank you.

All right. That's all of the appearances.

Are there any housekeeping matters to be taken up at this time?

(No response.)

CHAIRMAN SHAW: Okay.

COMMISSIONER PRIDEMORE: Mr. Chairman, if there are none from the parties, I have one.

CHAIRMAN SHAW: Go ahead, Commissioner Pridemore.

COMMISSIONER PRIDEMORE: Clean Energy Buyers Association, you're a new intervenor over this last cycle and definitely you didn't intervene in the

original IRP.

Can you tell me who your members are, who you represent?

MR. DUNBAR: Good morning, Commissioner. I don't have a list of our members in front of me. I can try to pull that up.

I'm happy to file something into the docket. There is well over 100 members of CEBA, I believe.

COMMISSIONER PRIDEMORE: That would be great. That would be great. Thank you.

MR. DUNBAR: And, sorry, just to clarify. The preference is to file something into the docket with the list of names?

COMMISSIONER PRIDEMORE: You can file it into the docket with the executive secretary's office a list of your members.

MR. DUNBAR: Certainly. Thank you.

COMMISSIONER PRIDEMORE: Thanks.

CHAIRMAN SHAW: Any other housekeeping matters?

(No response.)

CHAIRMAN SHAW: All right. We'll go ahead and call for public witnesses. I know we have some folks on the sign-up sheet. If I miss anyone, just let us know at the end. I will start with the first on the list, Jake Tench.

And if I say a name wrong, please correct me on that, as well.

MR. TENCH: Good morning, Mr. Chair.

CHAIRMAN SHAW: And our rules are three minutes each. So you've got the time clock on the screen there for you.

MR. TENCH: Perfect. I'm hoping to hit a minute and a half, but thank you, Mr. Chairman and Commissioners. My name is Jake Tench. I am with Georgia Agribusiness Council. We are a trade association that represents over 1,300 members spanning pretty much across the entire industry of agriculture, from producers to processors, dealers to retailers. And I just want to thank you for allowing me to come here today and speak.

At the Georgia Agribusiness Council, our main mission is to defend and support the state's largest industry with over $75 billion of economic impact and close to half a million jobs across the state. Agriculture is obviously vital to our state's success.

While I know most people these days think that food comes from the back of the grocery store and clothes magically appear on the department store shelves, we know that that is not the case. There's

a sophisticated network and a lot of allied industries that put the things that we need on a daily basis on those shelves.

As I mentioned earlier, when you look at agribusiness as a whole, it is a very complex industry. Georgia is blessed to have a very diverse industry that we oftentimes excel and lead the nation in. Although products such as cotton, peanuts, peaches, poultry, beef, all those things that we see or think immediately when we hear agriculture, all of these allied industries play a vital role and can contribute to those numbers that were mentioned earlier.

This kind of brings me to the purpose that I'm here today. All of these things would not work without the efficient and reliable public services that have allowed this industry to be what it is. I'm sure it's no news to you-all that reliable electricity in particular is an absolute necessity, whether it be a poultry processing plant that employs 2,000 people or a cold storge facility that has a million pounds of protein on the shelves, or a small family packing shed packing vegetables that a family depends on.

All of these things create the industry that we

know and rely on those resources. If one link of that supply chain becomes kinked due to unforeseen circumstances, the entire industry is backed up until it gets straightened out.

I'll wrap up with this: I just want to thank you-all for what you do. Thank you for the service that you provide to this state. And I know that these services can often be taken for granted, just like agriculture, and aren't truly appreciated until they're unavailable.

And, with that, I just want to -- to ask that as you evaluate Georgia's present and future needs in this sector that you will keep agribusiness in the forefront of your minds.

Thank you.

CHAIRMAN SHAW: Thank you, Mr. Tench. Thank you for what you-all do and represent the number one industry in our state.

Curt Harris.

MR. HARRIS: Honorable Chairman Shaw, esteemed Commissioners, my name is Dr. Curt Harris. I am the Director of the Institute for Disaster Management at the University of Georgia. I'm also a faculty member there and help policy and management in epidemiology and biostatistics within the College of Public

Health.

My institute encompasses an educationally diverse group of faculty and staff who are dedicated to fortifying Georgia's healthcare delivery systems and ensuring continuous operations, regardless of the challenges that may arise.

My presence here today primarily serves to underscore a critical, yet often overlooked cornerstone of Georgia's healthcare framework: The indispensability of reliable, swiftly restorable electrical grid. It is important to note that the conceptualization of healthcare infrastructure is not just limited to hospitals. It also includes, but is not limited to, dialysis clinics, pharmacies, behavioral health clinics, medical practices, emergency medical services, long-term care facilities, K-12 student health clinics, university health centers, public health clinics, hospice centers, fairly qualified health centers and many others.

Weather-related power outages have historically caused major health and economic implications across the United States. Previous diasters demonstrated the fundamental need for sustainable and reliable power across healthcare facilities. Chronically ill

patients, such as dialysis patients, can particularly be vulnerable to power losses. It is estimated that during Hurricane Katrina almost half of all renal disease patients missed one or more dialysis sessions, which can be extremely dangerous to their health.

In 2017, Hurricane Irma caused a healthcare facility in South Florida to lose its power. This happened to be a long-term care facility. As a result, nine residents in that facility died because they were not able to maintain heating and air conditioning. Also, as a result, the administration of that facility was actually brought up on manslaughter charges simply because they could not provide power in that area.

Power outages to non-healthcare infrastructure can also have indirect effects on healthcare facilities. In Austin, Texas, due to a power outage at a water treatment facility, healthcare facilities actually had to evacuate residents and patients to other healthcare facilities, which, again, can be extremely dangerous to their health.

In addition to that, pharmacies have a major implication on power outages. If we lose power, we have refrigerated and non-refrigerated medications

that have the potential to be lost. In Georgia, we actually had public health districts that had to get rid or actually destroy some medications due to the inability to maintain power in the aftermath of a hurricane.

As a result of this and many other instances, we -- it is our professional endeavors that are inextricably linked so we ask that this Commission consider the healthcare infrastructure as it relates to additional power, as well.

In closing, I sincerely thank you for the collaborative efforts that have been instrumental in upholding power reliability in Georgia healthcare facilities and I firmly hope that the mission remains central to your contemplations regarding Georgia's bourgeoning energy requirements.

Thank you.

COMMISSONER McDONALD: Are you suggesting that we have a reliability problem in Georgia?

MR. HARRIS: So the reliability issue is a lot of healthcare facilities, they're required to have backup power. But a lot of times that comes in the form of generators and generators are notoriously unreliable. They require significant maintenance. You have to be able to fuel them and you have to be

able to get fuel to them.

So particularly in the aftermath of disasters, that can be --

COMMISSONER McDONALD: Is that a responsibility of the Public Service Commission to maintain generators?

MR. HARRIS: It is the respons- -- it's not the responsibility of the Georgia Public Service Commission, no, sir, but it is a major issue that we have to deal with here because it has a major impact on healthcare. There's been ICUs that have lost power that don't have the ability to maintain it. With all the medical equipment that goes into that, medically ventilated, like, you require people to manually be able to do that.

COMMISSONER McDONALD: What do you suggest in your situation when a tornado comes through and trees are knocked down and power lines are knocked down and there is a source of energy that's not there for a period of time?

What do you suggest, other than maintaining those generators?

MR. HARRIS: Well, definitely maintaining the generators is another one. But just increasing our -- kind of our energy infrastructure that's out

there so that it is reliable and has the ability to be maintained and restored very, very quickly.

COMMISSONER McDONALD: Have you ever tried to go down the streets of a neighborhood and cut trees?

MR. HARRIS: Yes, sir, I have.

COMMISSONER McDONALD: You have?

Not from this end you haven't. It gets very difficult to --

MR. HARRIS: It is extremely difficult.

COMMISSONER McDONALD: Thank you very much.

MR. HARRIS: Yes, sir.

CHAIRMAN SHAW: Thank you, sir.

Aurora Gray. Good morning.

MS. GRAY: Good morning.

Hello. My name is Aurora Gray. Thank you for having me today. I attend Oberlin College. Thank you.

I, and many other students are here today, because we are deeply troubled by Georgia's Power updated IRP request for additional energy funding because this request ignores worldwide scientific communities urgent call for a rapid phasedown of fossil fuels and a transition to cleaner, renewable energy.

We are here today to ask you to exercise your

authority to require Georgia Power to not only include additional -- to not include additional fossil fuel energy sourcing or fossil fuel plant construction in its updated IRP. Instead, please require them to take responsible and safe actions to both reduce and meet energy demands.

An important part of the mission statement is to provide safe electricity to Georgia consumers and this is meaning -- this means the delivery of electricity to consumers without exposure to, you know -- I'm sorry. My apologies -- flammable chemicals, fires, et cetera.

Now, however, the generation of energy itself when done using fossil fuels has become an existential threat to our safety due to the undisputed impacts of greenhouse gas emissions on our planet. For this reason, we are asking you to reject Georgia Power's updated IRP proposal and require them to instead make major investments in clean, renewable energy production, battery storage, and energy-efficient programs.

We must act now, as later is way too late. As a group, we would like to share some history that relates to decisions you will be making and then talk about why natural gas is not a good bridge fuel, and

then to discuss what can be done to both meet and decrease the newly forecasted energy demand.

We understand that it is uncommon for Commissioners to respond or ask questions during public comments, but we ask that if you have any questions to please hold them to the end, if you can. Your questions may be answered by students in later comments.

Thank you.

CHAIRMAN SHAW: Thank you. Nikita Takalkar.

Did I mess it up too bad?

MS. TAKALKAR: No, sir. You did great.

CHAIRMAN SHAW: Thank you.

MS. TAKALKAR: Thank you so much for having me. My name is Nikita Takalkar. I'm a student at Georgia Tech. I'm going to focus on 1988, which was a pivotal year for our climate in several different ways.

Scientists had already understood for decades before 1988 that human produced -- that humans produce greenhouse gas emissions, such as carbon dioxide and methane, and that those would warm the plant.

But in 1988, climate change emerged as a front-page issue. There was a major heat wave that

killed thousands, inflicted billions of dollars in damage, and demonstrated to average citizens what a future of unmitigated climate change would look like.

Also in 1988, the Intergovernmental Panel on Climate Change was created. The IPCC delivers on a regular basis comprehensive scientific reports about climate change. Scientists from around the world selected for their expertise in their field volunteered their time and energy and collectively spend thousands of hours analyzing peer-reviewed research on climate change.

In 1990 and in 1992, the IPCC published their first reports stating with certainty that human-generated greenhouse gas emissions were contributing to climate change. And that some degree of warming had already occurred and doubling atmospheric CO2 content would likely cause 1.5 to 4.5 degrees Celsius of warming.

The IPCC underlined the global impacts of climate change and the necessity of international cooperation to combat this. But, unfortunately, in 1998 this was also a pivotal year for the Southern Company.

For decades prior to 1988, Southern Company executives had been privy to the latest scientific

information regarding human-produced greenhouse gas emissions, global warming, and the predicted devastating impacts. In fact, its own scientists were doing some of the cutting-edge research in the forefront of this field. But in 1988, as momentum for worldwide action to mitigate greenhouse gas emission was growing, the Southern Company buried that research and established itself as a driving force behind climate disinformation.

They backed misleading campaigns that attacked climate science, they opposed binding limits on greenhouse gas emissions, and they promoted clean coal as a false solution to the problem. And they fought to slow the transition to clean power and renewable energy sources, like wind and solar power.

This is well documented in the comprehensive 2022 report titled: Southern Company Knew. The report identifies over $62 million that the Southern Company paid to special interest groups and to outside firms involving campaigns against climate science and politics. The report only traces dollars spent from 1993 to 2004, and it acknowledges that it captures only a portion of the money that the Southern Company has spent to influence climate action.

Thank you very much for your time.

CHAIRMAN SHAW: Thank you.

Lily Mae Baruk.

Good morning.

MS. BARUK: Good morning. Hello. My name is Lily Mae Baruk. I'm a freshman at Georgia Tech, as well.

And I don't know if you can relate to the anger and the grief that this historical information that was just shared elicits from those of us who are young. You-all were born in a different world and most of your lives, the impact of climate change were minimal and not often really felt.

But from the time we were very young, we have been impacted by climate change. Those of us who grew up in Georgia have experienced many more really hot days each summer than you did as youth. At times, we've had practices, games, and other outdoor events canceled due to extreme heat. We've become accustomed to smog, exacerbated by heat, and wildfire smoke created by ultra dry conditions.

Almost 9 percent of children in Georgia suffer from asthma with many more going undiagnosed. Some of us have friends or family who've been greatly impacted by extreme climate change fueled weather

events. We know of people who've lost their crops due to extreme heat or drought, who've lost their homes and livelihoods due to massive fires, and who've had their houses and businesses flooded due to intense hurricanes or massive rainfall events.

We know that the consequences of climate change are unjust. We know that people with low incomes living near utilities and factories are impacted greatly by the pollutants they produce. We know that people living in the poorest countries and low-lying island nations, which are home to roughly 1 billion people, yet account for less than 1 percent of humanity's total planet warming pollution, are suffering its impacts the most.

On the news, we hear of so many people who have become climate refugees because their water and food sources no longer exist. They have no choice but to move so that they can survive.

Rising seas and other climate change fueled massive flooding events regularly lead to disease, death, destruction, and displacement of large numbers of people. And we know that unless dramatic action is taken, if we have children, they will be born into a world that is much, much -- that's in a much, much worse situation.

You must act now. Later is too late. It's hard to know that all of this could have been avoided, that over 35 years ago the science was already solid enough to justify global action to reduce greenhouse gas emissions.

It's inexcusable that sufficient action wasn't begun then. More than half of all greenhouse gas emissions have occurred since 1990 when the IPCC published its first report.

Thank you.

CHAIRMAN SHAW: Thank you.

VICE-CHAIRMAN ECHOLS: Hey, can I ask you a quick question?

Do you have a car?

MS. BARUK: Do I have a car? I do not have a car.

VICE-CHAIRMAN ECHOLS: Okay. Do any of your group have an electric car? Any of your group?

MS. BARUK: We -- we actually carpooled here today in an electric car.

VICE-CHAIRMAN ECHOLS: Yeah. Why do you think that young people are not buying used EVs that are really cheap; Nissan Leafs?

Why do you think they're opting for other cars, instead of EVs, if the crisis is as you've described?

MS. BARUK: I think -- I think it's hard for young people to be able to pay for that. But it's also that when technology becomes more available, that it will be easier for people to access things like that.

VICE-CHAIRMAN ECHOLS: So convenience primarily?

MS. BARUK: And resources.

VICE-CHAIRMAN ECHOLS: Resources, okay. Thank you.

CHAIRMAN SHAW: Flannery Childers. Good morning.

MS. CHILDERS: Good morning. Hello. My name is Flannery Childers and I'm a senior at Decatur High School. A particularly egregious public example of climate science denial took place in 2017.

Tom Fanning, then CEO of Southern Company, was asked on national television if he believed that it had been proven that carbon dioxide was the primary driver of climate change. His response: No, certainly not.

This, despite the fact that in 2013 and 2014 the IPCC had published reports stating that human influence on the climate system is clear and limiting climate change requires substantial and sustained

reductions of greenhouse gas emissions.

And in 2015, virtually every nation had signed on to the Paris Agreement committing to pursuant efforts to hold global warming to 1.5 degrees Celsius. Why? Because the science indicated that beyond that temperature increase, the impacts of catastrophic heat waves, flooding, drought, crop failures, and species extinction would become significantly harder for humanity to handle.

But it must have been difficult for Mr. Fanning to publicly agree with the science no matter how convincing or accepted, despite the fact that scientists had already been warning for years that natural gas might be as bad as coal. In 2016, Southern Company made a big investment in natural gas. They acquired the gas company AGL Resources.

Was there any attempt by other utility CEOs to correct Mr. Fanning? Most were asked directly and two replied with brief written comments. But from Georgia Power and the rest? No. Crickets.

Likely because most utilities were paying dues to organizations that were still trying to use that, "It's not certain yet" argument to prevent policies to limit coal and natural gas production. They certainly couldn't convince everyone to reject the

climate science at that point, but they just needed enough to prevent climate action.

Now Georgia Power has presented you with an updated request for its 2023 IRP. They are asking for a significant increase of 30 percent of natural gas to generate new electricity, permission to build new fossil fuel plants, and the option to keep some coal-fired plants running past previously projected shutdown dates. The answer to these requests must be a resounding no.

Thank you.

CHAIRMAN SHAW: Thank you.

Dylan Holley.

Good morning.

MR. HOLLEY: Good morning. Hey, y'all. My name is Dylan Holley. I'm a student at Georgia Tech.

It is a given that Georgia Power's coal plants must be shut down as scheduled or even faster. Coal has not been economically viable for years and burning it produces large amounts of CO2. It has also been determined that coal, particularly Manter, is particularly damaging, attributable to thousands of deaths each year, high rates of asthma and other physical ailments. And there is an expensive problem of how to safely dispose of dangerous coal ash.

So what about natural gas? The burning of natural gas produces about half the carbon dioxide as compared to burning coal. That is still a lot of CO2, particularly with our very, very limited carbon budget, with the main component of natural gas 75 to 95 percent is methane, a much more powerful greenhouse gas in the short term. Our understanding of its danger, and, therefore, the danger of natural gas has grown substantially in recent years.

From 2012 to 2018, the Environmental Defense Fund coordinated a groundbreaking research project involving more than 140 researchers and 40 institutions. The goal, to establish a reliable benchmark of the methane emissions from the oil and gas industry.

They discovered that methane emissions were 60 percent higher than previous estimations by EPA and the industry, putting the rate of methane emissions from domestic oil and gas from operations at 2.3 percent of total production per year.

This is incredibly alarming, given that a peer-reviewed study published in July of 2023, involving researchers from Brown, Harvard, Duke, and NASA found that it takes as little as 0.2 percent of gas to leak to make it as big a driver of carbon

change as coal.

That is a very difficult amount for utilities to maintain and monitor and leaves just a tiny margin of error for a gas that is notorious for leaking from drill sites, processing plants, and pipes that transport into power stations, homes, and kitchens.

Thank you.

VICE-CHAIRMAN ECHOLS: Can I ask you a quick question?

MR. HOLLEY: Yeah.

VICE-CHAIRMAN ECHOLS: You're talking about fugitive methane; right?

You're not talking about burning methane?

Methane that's escaping from leaky pipes --

MR. HOLLEY: Yeah.

VICE-CHAIRMAN ECHOLS: Fugitive methane.

Are you aware of Dr. Marilyn Brown, Professor at Georgia Tech?

MR. HOLLEY: No, sir.

VICE-CHAIRMAN ECHOLS: Are you familiar with her and her Drawdown Georgia report that talks about how burning methane in Atlanta has reduced greenhouse gases and it's been the primary driver for improving our air quality?

Are you familiar with that report?

MR. HOLLEY: No. I'm not an expert on the subject. I'm just bringing you what the scientists are saying.

VICE-CHAIRMAN ECHOLS: Thank you.

MR. HOLLEY: Thank you.

CHAIRMAN SHAW: Thank you, sir.

Natalie Mouldin. Natalie -- oh, there you are. Good morning.

MS. MOULDIN: Good morning.

Hello. My name is Natalie Mouldin and I'm a junior at Decatur High School. Thank you for your time.

I will be speaking more about dangers of natural gas. A Stanford University study published in July of 2022 focused on the emissions of methane after natural gas arrived in home kitchens. They found that the average natural gas stove is estimated to emit .8 to 1.3 percent of the gas used as unburned methane. More than 75 percent of this leakage occurs while the stove is turned off.

There are also super-emitter events. Using advances in satellite technology, it was estimated that a large gas well leak in Ohio in 2018, just over a 20-day period, released more methane than some European countries emit in a typical year.

Natural gas could have been a part of the solution today if we had begun taking serious climate action 35 years ago. Because methane doesn't remain in the atmosphere nearly as long as CO2, natural gas could have been a bridge fuel, even with the significant leakage. But now we are in a climate emergency.

In their most recent assessment in March of 2023, the IPCC said that continuing insufficient action to limit greenhouse gas emissions has set us on a course to reach the critical 1.5 degree Celsius threshold in about ten years.

Since methane is 80 times more powerful than CO2, in a 20-year period the continued reliance on natural gas at current levels would be a primary driver of pushing past that threshold. But a rapid reduction of methane could be our salvation. That's why 155 countries have signed the global methane pledge targeting a cut in methane emissions of 30 percent of 2022 levels by the year 2030.

Georgia Power must do its part. They must not increase their use of natural gas for energy sourcing and they must not build new natural gas plants. Instead, Georgia Power needs to start aggressively planning down a phasedown on electricity generated by

fossil fuels, aligned with the targets of the international scientific community.

They must act now. Later is too late. Thank you.

CHAIRMAN SHAW: Thank you.

Taylor Myers.

MS. MYERS: Good morning. My name is Taylor Myers. I'm a junior at Decatur High School. And before I start talking about the utility knuckle of solar and batteries, I would like to say --

COMMISSONER McDONALD: Talk a little closer to that mike, please.

MS. MYERS: I would like to say --

COMMISSONER McDONALD: Better.

MS. MYERS: -- yes, I have an electric car.

So what can be done to ensure that there is enough energy to meet future demand in Georgia? Well, first, Georgia Power must make a much larger investment in utility-level solar and batteries than is planned for their current IRP request.

The Georgia Public Service Commission published Georgia Power to include utility-level solar starting in 2013. And Georgia is now, I believe, fifth or sixth in the nation for the amount of utility-level solar that has currently -- that has currently been

installed.

You-all definitely deserve praise for this, with special recognition to Congressman McDonald. Thank you.

VICE-CHAIRMAN ECHOLS: You just got a raise.

MS. MYERS: However, utilities across the board --

COMMISSIONER PRIDEMORE: You got a raise.

MS. MYERS: However, utilities across the board have been really lagging in clean energy sourcing.

The 2023 report, "The Dirty Truth About Utility Climate Pledges" puts Georgia's efforts in perspective. It demonstrates that almost all of the pledges made by utilities to transition -- to transition to clean and renewable energy are not ambitious enough in that the utilities are not even meeting their own low targets.

And while many utilities have pledges for 2050, the major -- the majority lack critical intermediate targets. So it is clear that we shouldn't compare ourselves to the low level of clean energy sourcing that most utilities have been achieving.

How do we compare to the states in utilities that are doing the best in utility-level solar? Not very well. California has held the number one spot

for decades. The state currently has 17,277 megawatts of utility-level solar installed on its grid as compared to about 4,000 megawatts in Georgia.

Just this year, though, California was surpassed by Texas. Texas has 18,364 megawatts of solar capacity installed on its grid as of September 2023. The vast majority of that was added since 2019. They nearly doubled the capacity from 2019 to 2020 and then doubled it again between 2020 and 2021.

Also, Texas has a total capacity of 3,300 megawatts of grid battery installation, almost all of which came online since early 2021. Yes, Texas is larger than the U.S., but Georgia Power is saying that we need to add 600- -- 6,600 megawatts of new energy sourcing quickly. And Texas illustrates that it is possible to do much or all of that utility-level, solar plus battery. And most of Texas' increased solar and battery installations occurred before the inflammation -- Inflation Reduction Act passed in 2022. Thank you.

CHAIRMAN SHAW: Thank you.

Josephine Threlkeld.

Good morning.

MS. THRELKELD: Good morning. Hello. My name is Josephine Threlkeld and I'm a sophomore at Decatur

High School.

Commissioners, the IRA is a game changer. It has been heralded as the most significant climate legislation in history and it includes a multitude of provisions that support utilities transition to clean energy. Available tax credits lower wind, solar and storage project costs by a minimum of 30 percent. According to several analyses, this makes 99 percent of gas plants more expensive than a clean energy mix alternative.

It is also important to know that these analyses do not take into account the economic stranded assets. If Georgia Power is going to be part of meeting Southern Company's net zero greenhouse gas emissions goal by 2050, then any new gas plants will eventually become stranded assets.

Even if they come -- even if they came online by 2025, that leaves them with, at most, 25 years of productivity, out of a predicted lifetime of 40 years.

If Southern Company and Georgia Power were to establish the interim target goal that the worldwide scientific community says are critical, then those assets become obsolete much sooner. The stranded asset situation makes investing in new fossil fuel

plants considerably more wasteful and costly relative to investments in solar and batteries.

Texas is also an example of what energy system researchers have been saying for years. A combination of wind, solar and battery storage are often more reliable than fossil fuel generation to handle periods of extremely high demand, especially if these peaks occur for short durations during a day.

During the historic heat wave Texas had last summer, during which many all-time record highs were broken, the new low cost wind, solar, and batteries kept the grid afloat and Texans cool. In many cases, saving lives.

From a July 2nd, 2023, Forbes article, quote, Solar and wind provide a 35 percent of statewide power last Tuesday and generated a record 31,500 megawatts Wednesday, which more than covered the 9,600 megawatts of electricity lost when extreme heat knocked several natural gas and coal plants offline. And just as the solar power started falling in the evening, batteries kicked in immediately to get Texas through the most difficult part of the day when the sun was setting, but the A/Cs were still cranking, unquote.

Please act now to require Georgia Power Company to take advantages of the provisions in the IRA and greatly expand investment in utility-level solar and battery storage. You must act now. Later is too late. Thank you.

CHAIRMAN SHAW: Thank you.

I'm probably going to mess this one up. It's not clear. Andrew Zhao.

MR. ZHAO: Good morning. Andrew Zhao.

CHAIRMAN SHAW: Oh, okay. Sorry.

MR. ZHAO: No worries. Hi. My name is Andrew Zhao. I'm a recent graduate of Georgia Tech and now resident of Atlanta.

And Georgia Power must also reinstate the RNR net metering program to promote rooftop solar growth throughout Georgia. Georgia has great rooftop solar potential and rooftop solar could be an important asset in reducing Georgia's peak energy demand.

That peak demand occurs during the summer on hot, sunny days between 2:00 p.m. and 7:00 p.m. For much of that five-hour time period, rooftop solar panels can produce enough electricity to both power the building they are placed upon, reducing the amount on the grid, and add excess electricity back to the grid.

But why are we currently ranked 43rd in the U.S., in terms of rooftop solar? Why? As witness Dr. Marilyn Brown so thoroughly explained in her testimony before the Commission, which I believe you mentioned one of her reports before, it is because of our net metering policies. Those states with the best net metering policies are more rooftop solar. Those with the worst have less.

For years, with the exception of a short period when people were able to sign up under the RNR net metering pilot program, Georgia has had one of the very worst policies. At least 33 states have adopted net metering policies which credit excess electricity generated by customers at the retail rate. Almost all of the 33 still have those policies in place. That is what is needed to really growth rooftop solar.

In the testimony -- in their testimonies during the 2022 IRP hearings, witnesses Alden Hathaway and Kevin Lucas, using supporting data and examples from other utilities, demonstrated that distributed solar generation can be critical -- can be a critical resource to increase overall system load factors. This increases reliability and resilience and could result in significant reductions in system costs that

would save money for all customers. Thank you.

CHAIRMAN SHAW: Thank you.

Keerthana Nagula.

CHAIRMAN SHAW: Good morning.

MS. NAGULA: Good morning. Hello. My name is Keerthana Nagula and I'm also a student at Georgia Tech.

Rooftop solar has so many other economic benefits. Here are a few: First, the rooftop solar industry would see great growth. Rooftop solar is more labor intensive than utility-level solar. And this would result in the creation of many good paying jobs.

Also, if Georgia was to reinstate true net metering, we could eventually reach Drawdown Georgia's target of 295,000 solar rooftops. Witness Alden Hathaway estimated that this would bring in on average nearly $250 million per year in IRA government funds. Witness Dr. Marilyn Brown estimates that we've already lost $429 million in government funding, given our policies that we have not encouraged sufficient growth in the rooftop solar market.

Churches and schools that have solar panels on their buildings and over their parking lots would

greatly reduce their energy bills. Schools can invest more money in serving their students and churches could provide more valuable services for their community. And churches and school buildings with solar and battery storage could function as emergency centers providing a warm or cool place for vulnerable populations during power outages and extreme weather events.

Neighbors with rooftop solar and batteries can help out their neighbors when the power goes out. They can provide comfortable shelter and make room in freezers and refrigerators for food to protect it from spoiling in case of extended outages.

And, of course, with less energy generated using fossil fuels, there would be less air pollution. This would lead to less asthma and other health problem, saving Georgians on healthcare costs. Thank you.

VICE-CHAIRMAN ECHOLS: Can I ask you one question?

MS. NAGULA: Yes.

VICE-CHAIRMAN ECHOLS: You're going to have to get back with me on this.

MS. NAGULA: Okay.

VICE-CHAIRMAN ECHOLS: So since we've ended net

metering -- or the pilot is still going. But since we ended our pilot, the average solar array is about 7 kilowatts compared to 10. So if we were to add the 295,000 that you mentioned and they were 10 kilowatts, instead of 7, based on our average weather, how much energy would be -- would we be putting back on the grid every day?

Could you get back with me on that math problem?

(No response.)

VICE-CHAIRMAN ECHOLS: Just say yes.

MS. NAGULA: I'm not a math student.

VICE-CHAIRMAN ECHOLS: Between all your Tech friends, you can do it.

MS. NAGULA: I'm not an expert. So I'm just here to point you towards what the scientific community is saying. I'm sorry. So I don't have an answer.

VICE-CHAIRMAN ECHOLS: If any of you want to work on it, get back with me later. TEchols@PSC.ga.gov. Thank you. It's not a trick question.

COMMISSIONER JOHNSON: We have a volunteer back there.

VICE-CHAIRMAN ECHOLS: Okay. Great.

CHAIRMAN SHAW: Thank you, ma'am.

Annabelle Nyberg.

MS. NYBERG: Hi. I'm Annabelle Nyberg. I'm a first year at Georgia Tech. I have three points to make about Georgia Power's argument against expanding net metering.

First, Georgia Power was ordered to provide a cost service study to support any alleged cost shift to non-rooftop solar customers. Instead, they relied primarily upon a revenue erosion analysis and they provided minimum data to support their conclusions.

Second, Georgia Power used California, which just recently changed its net metering policies, as a warning case against net metering in general. This makes no sense. California is light-years beyond our level of rooftop solar penetration.

The Georgia Public Service Commission is fully capable, far off in the future when we begin to approach California's level of rooftop solar, of adjusting the net metering policy, if necessary.

Witness Dr. Marilyn Brown states that: I don't think that we're ever going to be in a situation where California is. We're going to be blessed with a whole lot of gadgets in our houses that will change the complex of electrification in favor of more

rooftop solar.

Finally, Georgia Power was unable to use one of the scientists, Ahmad Faruqui, who testified for them in 2019 against expanding the RNR net metering program. He has recently publicly changed his 2019 position.

He now claims that rooftop solar, especially with battery storage, reduces transmission and distribution costs across the system. He states that where solar deployment is in the early stages, where less than 5 percent of customers have deployed solar roofs, utilities should stick with net metering that credits excess electricity generated at the retail rate.

Only .2 percent of Georgia Power's customers currently have rooftop solar, 1/25th of the 5 percent figure he posits. Others believe that any potential cost shift concerns wouldn't arise until Georgia reaches around 10 percent solar penetration levels. Thank you.

CHAIRMAN SHAW: Thank you.

Neil Sardano.

MR. SARDANO: Hello, Commissioners. How are you-all doing this morning?

CHAIRMAN SHAW: Good morning.

MR. SARDANO: My name is Neil Sardano. I'm here representing the Georgia Conservation Voters Education Fund.

And I would like to ask you to reject, or at least significantly reconsider, Georgia Power's massive expansion of gas power in their 2023 IRP Update. As we've seen very recently, the Commission had to levy a fairly significant rate increase on to Georgia Power customers due to the cost of fuel last year. And the vast majority of that fuel cost increase was due to gas power.

And we've seen Georgia Power has increasingly relied on gas power as its main source of energy to provide to its customers and the proposal in the '23 IRP Update only significantly expands that utilization of gas power.

In addition to this, you know, cost that customers have -- now have occurred, you know, we have seen the Commission increase rates, you know, due to the other decisions it has made regarding Plant Vogtle. And there has been continued rate increases in the previous rate cases, which has levied significant amounts of rate increases on Georgia customers at times in which they're being absolutely crushed by inflation. And, unfortunately,

this Commission has been fully, you know, engaged in that process of allowing the energy inflation to occur by passing those costs on to customers.

So I ask that you consider, you know, a clean energy alternative. We've heard a lot of evidence today about clean energy, about solar power as a great opportunity within our state. In fact, you know, we are here in the Sunbelt.

Solar power is literally the best -- you know, the greatest advantage that Georgia has compared to all other, you know, forms of energy and across many of the states across our nation. We should be utilizing our competitive advantage for the use of all citizens so that they can have more reliable, more affordable, and cleaner energy that provides them with a much better investment on their return.

You know, the public needs to have their voice listened to and it's time the Public Service Commission listens to the voices of the public on these issues. Thank you very much.

CHAIRMAN SHAW: Thank you.

That is the end of the list. Were there any -- is there anyone else who came in after we started that wanted to provide comments as a public witness?

(No response.)

CHAIRMAN SHAW: Okay. Before we call up Georgia Power to swear in the panel, I'll just -- even though we don't have windows here, there is the possibility of some significant weather in the region today. So we're monitoring that closely.

And if we have any directives from -- from Capitol Hill, we will respond accordingly. But we do not plan to go extremely late because we want to make sure that everyone can get on the road and not be driving in the dark and so forth.

But thanks for all the public witnesses for taking the time to be here today, especially all you students for taking the time to engage and be a part of this.

We have a lot of parties. I'll just remind everyone that just please try to pay attention. And if there's a question that's already been asked, try not to ask a question that has already been answered.

All right. Georgia Power, do you want to swear in your panel?

MR. HEWITSON: Thank you, Mr. Chairman. I will give them a second to come in.

Commissioners, at this time I will call Georgia Power's panel of witnesses on direct, Jeff Grubb, Franciso Valle, Lee Evans and Mike Bush. I'll note

for the record that we have filed the notice of publication, as required by the Commission's rules.

Gentlemen, if you would please raise your right hands.

Thereupon,

Jeffrey R. Grubb,
Francisco Valle,
Lee Evans,
Michael A. Bush,

having been duly sworn, testified as follows:

DIRECT EXAMINATION

BY MR. HEWITSON:

Q Mr. Grubb, would you please start by stating your full name, your employer, and your responsibilities for the record.

A (Witness Grubb) Yes. My name is Jeffrey R. Grubb. I'm the director of resource policy and planning with Georgia Power Company where I lead the team that guides the company's generation planning activities, including the IRP development, IRP updates, and making sure we meet the customers' capacity needs.

Q Okay. Mr. Valle.

A (Witness Valle) Hi. My name is Francisco Valle. I'm director of forecasting analytics and responsible for providing this Commission with the load forecast.

Q Okay. And Mr. Evans.

A (Witness Evans) Lee Evans, director of economics and load flexibility for Southern Company. Responsible for doing cost analysis, economic analysis, and designing load flexibility programs for customers.

Q And Mr. Bush.

A (Witness Bush) Good morning, Commission. My name is Mike Bush. I'm director of generation planning and development for Southern Company's services. I'm responsible for developing and deploying new generation.

Q Thank you, gentlemen.

Mr. Grubb, on October 27, 2023, did you file or cause to be prefiled Georgia Power Company's 2023 Integrated Resource Plan Update, including the trade secret technical appendices?

A (Witness Grubb) Yes, I did.

MR. HEWITSON: Okay. Chairman Shaw, for the record, I would like to identify Georgia Power Company's 2023 IRP Update as Exhibit GPC 1 for the trade secret version and GPC 2 for the public disclosure version.

CHAIRMAN SHAW: So marked.

(The documents referred to were marked for identification as GPC's Exhibits 1 and 2.)

BY MR. HEWITSON:

Q Mr. Grubb, on December 4, 2023, did you prefile

or cause to be prefiled 56 pages of direct testimony in question-and-answer format?

A (Witness Grubb) Yes, I did.

Q Are there any corrections you need to make to your prefiled testimony?

A (Witness Grubb) There are not.

Q Okay. If I were to ask you the same questions today under oath, would your answers be the same as they are set forth in that prefiled testimony?

A (Witness Grubb) They would.

MR. HEWITSON: Okay. Chairman Shaw, the court reporter has been provided a copy of the prefiled direct testimony and I now ask that the direct testimony of this panel be copied into the record as if given here today.

CHAIRMAN SHAW: So marked.

(Whereupon, the prefiled direct testimony of Mr. Jeffrey R. Grubb, Franciso Valle, Lee Evans and Michael Bush follows:)

STATE OF GEORGIA

BEFORE THE

GEORGIA PUBLIC SERVICE COMMISSION

In Re:

Georgia Power Company's	**)**	**Docket No. 55378**
2023 Integrated Resource Plan Update	**)**	

DIRECT TESTIMONY OF

JEFFREY R. GRUBB, FRANCISCO VALLE, LEE EVANS,

AND MICHAEL A. BUSH

DECEMBER 4, 2023

DIRECT TESTIMONY OF
JEFFREY R. GRUBB, FRANCISCO VALLE, LEE EVANS,
AND MICHAEL A. BUSH

IN SUPPORT OF GEORGIA POWER COMPANY'S
2023 INTEGRATED RESOURCE PLAN UPDATE
DOCKET NO. 55378

I. INTRODUCTION

Q. PLEASE STATE YOUR NAMES, TITLES, AND BUSINESS ADDRESSES.

A. My name is Jeffrey R. Grubb. I am the Director of Resource Policy and Planning for Georgia Power Company ("Georgia Power" or the "Company"). My business address is 241 Ralph McGill Boulevard, N.E., Atlanta, Georgia 30308.

A. My name is Francisco Valle. I am the Director of Forecasting and Analytics for Southern Company Services ("SCS"). My business address is 241 Ralph McGill Boulevard, N.E., Atlanta, Georgia 30308.

A. My name is Lee Evans. I am the Director of Economics and Load Flexibility for SCS. My business address is 241 Ralph McGill Boulevard, N.E., Atlanta, Georgia 30308.

A. My name is Michael A. Bush. I am the Generation Development Director for SCS. My business address is 600 North 18th Street, Birmingham, Alabama 35203.

Q. MR. GRUBB, PLEASE SUMMARIZE YOUR EDUCATION AND PROFESSIONAL EXPERIENCE.

A. I began my career with Georgia Power in 1992 as a cooperative education student in Commercial and Industrial Marketing. I graduated from the Georgia Institute of Technology in 1996 with a Bachelor of Science degree in Mechanical Engineering.

After joining the Company as a full-time employee in 1997, I worked in various roles within Marketing until 2001, at which time I participated in a Company developmental program where I gained experience in a wide range of functional areas. During this period, I earned a Master of Business Administration degree from Auburn University in 2000.

In 2003, I joined the Resource Policy and Planning organization at Georgia Power where I served as a Project Manager through 2006. From 2007 through 2016, I worked for SCS in various planning roles, including SCS Forecasting Team Leader (2007), SCS Fuels Planning Manager (2007-2011), and SCS Resource Planning Project Manager (2011-2016), where I managed the team that supports the development of the Southern Company System ("System") Integrated Resource Plan ("IRP"). In this role, I supported Georgia Power's 2013 IRP (Docket No. 36498) and 2016 IRP (Docket No. 40161). In 2016, I returned to Georgia Power as Project Manager in Resource Policy and Planning, where I worked on the development of the 2019 IRP. Beginning in March 2018, I assumed my current position as Director of Resource Policy and Planning for Georgia Power.

Q. MR. GRUBB, HAVE YOU PREVIOUSLY TESTIFIED BEFORE THE GEORGIA PUBLIC SERVICE COMMISSION?

A. Yes. I testified in Docket No. 44160, Georgia Power's 2022 IRP; Docket Nos. 4822, 16573, and 19279, the Georgia Public Service Commission's ("Commission") Review of Georgia Power's PURPA Avoided Cost Methodology; Docket No. 42310, Georgia Power's 2019 IRP; Docket No. 42625, Georgia Power's Application for the Certification of the 2020/2021 Renewable Energy Development Initiative ("REDI") Utility Scale Power Purchase Agreements ("PPAs"); Docket No. 41596, Georgia Power's Application for the Certification of the 2018/2019 REDI Utility Scale PPAs; Docket No. 41734, Georgia Power's Application for the Certification of the 2018/2019 REDI Utility Scale PPAs for the Commercial and Industrial ("C&I") Program.

Q. MR. VALLE, PLEASE SUMMARIZE YOUR EDUCATION AND PROFESSIONAL EXPERIENCE.

A. I graduated from the Universidad Técnica Federico Santa María in Valparaíso, Chile in 1997 with a degree in Electrical Civil Engineering. I also hold a Master of Business Administration from Emory University's Goizueta Business School.

I joined Southern Company in 1997 as a planning analyst at Edelnor S.A., a subsidiary of Southern Energy Inc., in Santiago, Chile. In 2001, I moved to Atlanta to join Mirant Corporation, where I held multiple roles of increasing responsibility in system planning and market development and gained extensive experience modeling power pools in the United States and valuing generation technologies and demand response. Since then, I have worked at SouthStar Energy Services, a subsidiary of Southern Company Gas, and served as the Manager of Risk Analysis Services, a group within the SCS Finance organization. In this role, I was responsible for supporting the selection of optimal financing strategies for the company's debt and equity portfolios and for providing business units with quantitative analysis and risk mitigation strategies. I also supported Georgia Power Market Planning by providing revenue, load forecasting, and risk analysis; performing weather revenue variance analysis; reviewing features of load forecasting models; and more.

In September of 2021, I joined Georgia Power as Director of Market Planning. In this role, I led Georgia Power's Forecast and Profitability & Economic Analysis teams, which produced, among other things, the annual peak demand, energy, and revenue forecasts, as well as profitability evaluations of demand side management ("DSM") programs. In March of 2023, I assumed my current position as Director of Forecasting and Analytics for SCS. I lead the forecasting team that provides load forecasting services to SCS, Georgia Power, and Mississippi Power Company ("Mississippi Power") as well as the quantitative team that supports capital market operations and provides operational analytics.

Q. MR. VALLE, HAVE YOU PREVIOUSLY TESTIFIED BEFORE THE COMMISSION?

A. Yes. I testified in Docket No. 44160, Georgia Power's 2022 IRP.

Q. MR. EVANS, PLEASE SUMMARIZE YOUR EDUCATION AND PROFESSIONAL EXPERIENCE.

A. I received a Bachelor of Science degree in Financial Management from Clemson University in 2006 and a Master of Science degree in Finance from Georgia State University in 2013. I have also served as an Adjunct Instructor of Finance for the University of West Florida. I am a licensed Certified Public Accountant and a member of the American Institute of Certified Public Accountants. Additionally, I am a member of the Southeastern Electric Exchange's Rates and Regulations and Demand-side Management committees, the Edison Electric Institute Rates and Regulatory Affairs committee, and a board member of the Peak Load Management Alliance.

I began my career as an intern with SCS in 2006 and worked in various roles within the Accounting and Corporate Finance organizations. In 2011, I joined Gulf Power Company ("Gulf Power") in Revenue Accounting and later Regulatory and Cost Recovery. In 2015, I became the Pricing, Costing & Load Research Supervisor, where I oversaw the planning, implementation, and evaluation of retail electric prices, the planning and production of cost studies, and the load research function. Then, in 2018, I worked as a Project Manager in Georgia Power's Pricing & Rates organization leading various costing and pricing initiatives.

Beginning in 2019, I assumed roles of increasing responsibility at SCS, each of which oversaw developing and supporting system marginal costing tools, regulated cost-of-service studies and economic analysis. My current responsibilities, in addition to the costing function, include developing strategies and overseeing

analyses that influence end-use customer demand, designing load flexibility programs, and the integration of these programs into the planning process.

Q. MR. EVANS, HAVE YOU PREVIOUSLY TESTIFIED BEFORE THE COMMISSION?

A. Yes, I testified before this Commission in Docket No. 44160, Georgia Power's 2022 IRP, and in Docket No. 44280, Georgia Power's 2022 Rate Case.

Q. MR. BUSH, PLEASE SUMMARIZE YOUR EDUCATION AND PROFESSIONAL EXPERIENCE.

A. I began my career with Mississippi Power Company ("Mississippi Power") in 1983 as a cooperative education student. I graduated from Auburn University with a degree in Electrical Engineering. After working outside the Southern Company for a few years, I returned to work for Mississippi Power in 1990. From 1990 until 1995, I held various staff positions before transferring to SCS in Birmingham, Alabama to work in the wholesale marketing organization.

I became a Term Trader in 1996 and I was appointed Manager of Energy Trading in 1999. In 2003, I took the position of Director of Portfolio Management. After a re-organization of the wholesale organization occurred in 2005 combining Portfolio Management and Energy Trading, I took a leadership position in that new organization. In 2009, I moved to my current role as Director of Generation Planning and Development. My current responsibilities include providing generation planning and development services to Southern Company's retail operating companies, including Georgia Power.

Q. MR. BUSH, HAVE YOU PREVIOUSLY TESTIFIED BEFORE THE COMMISSION?

A. Yes. I was a rebuttal witness in Docket No. 40161, Georgia Power's 2016 IRP, and a direct witness in Docket No. 42310, Georgia Power's 2019 IRP.

Q. WHY IS GEORGIA POWER FILING THIS 2023 IRP UPDATE?

A. The Company files this update in response to significant changes that have occurred since the 2022 IRP was approved by the Commission. Most importantly, Georgia has experienced rapid economic growth in the intervening months following the 2022 IRP. This extraordinary growth requires that Georgia Power develop new supply- and demand-side capacity resources to meet substantial increases in customer demand and the energy needs of our state. To address the pressing need for capacity being driven by the extraordinary economic growth taking place in Georgia, the Company filed the 2023 IRP Update. In the Update, the Company (i) identifies the significant changes in the Company's Load and Energy Forecast since the 2022 IRP resulting from economic growth, (ii) explains the impact of this growth on the timing and magnitude of the Company's capacity needs, and (iii) presents a comprehensive and flexible resource plan to meet the rapidly growing energy needs of its customers. The 2023 IRP Update is consistent with Commission Rules 515-3-4-.06(5) and 515-3-4-.06(6), which require that the Company amend its IRP if it anticipates submitting an application for a certificate to construct or purchase a supply-side capacity resource or demand-side resource that was not previously approved as part of the IRP, or finds that other conditions warrant an amendment, such as an increase in the projected load forecast.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of our testimony is to present, explain, support, and seek approval of Georgia Power's 2023 IRP Update. As such, our testimony provides additional support for the Load and Energy Forecast underlying the Company's request, the Company's increased and accelerated capacity needs, and the resource plan developed to address these needs. More specifically, our testimony supports the following specific requests:

1. Authorization to procure the resources described in items 2-6 and 9 below in accordance with Commission Rules through the exceptions to the

Commission's Request for Proposals ("RFP") process set forth in Commission Rules 515-3-4-.04(3)(f)(3), 515-3-4-.04(3)(f)(6), and 515-3-4-.04(3)(f)(7).

2. A certificate of public convenience and necessity for the PPA between Georgia Power and Mississippi Power as described in Attachment A and the Technical Appendix.
    a. Regulatory asset treatment to defer the capacity and non-fuel energy payments made under the PPA, including additional sum, net of the wholesale capacity and non-fuel revenues from any remarketed capacity sales from January 1, 2024, through December 31, 2025, including an executed system sale to a regional electrical service provider during that time, for recovery in the next base rate case.
3. A certificate of public convenience and necessity for the PPA between Georgia Power and Santa Rosa Energy Center LLC as described in Attachment B and the Technical Appendix.
    a. Regulatory asset treatment to defer the capacity and non-fuel energy payments made under the PPA, including additional sum, net of any wholesale capacity and non-fuel revenues from any remarketed capacity sales from January 1, 2024, through December 31, 2025, for recovery in the next base rate case.
4. Authority to develop, own, and operate up to 1,000 MW of Battery Energy Storage Systems ("BESS") at various sites as described in this IRP Update and the Technical Appendix.
    a. Approval that any development costs not useful or transferable to other projects be deferred to a regulatory asset for recovery in the next base rate case in the event this request is denied.
5. Authority to develop, own, and operate up to 1,400 MW from three simple cycle combustion turbine ("CT") resources at Plant Yates as described in this IRP Update and the Technical Appendix.

a. Approval that any development costs not useful or transferable to other projects be deferred to a regulatory asset for recovery in the next base rate case in the event this request is denied.

6. Approval of two new customer-sited distributed energy resource ("DER") programs as described in this IRP Update.
7. Approval of one new tariff-based demand response program as described in this IRP Update.
8. Approval of an amended certificate for one existing demand response DSM program as described in this IRP Update and Attachment C.
9. Approval of the Flex Capacity framework as described in Section VII of this testimony.
   a. Regulatory asset treatment to defer any developmental costs for such activities that would otherwise be expensed for recovery in the next base rate case.
10. Transmission system improvements to accommodate the above-requested resources needed in support of the Company's Load and Energy Forecast as described in the Technical Appendix.

We adopt the 2023 IRP Update filed on October 27, 2023 as part of our testimony.

Q. PLEASE SUMMARIZE THE TESTIMONY OF THE PANEL.

A. Georgia continues to be one of the fastest growing states in the country and is experiencing extraordinary economic development. The tremendous growth that has occurred since the 2022 IRP is projected to significantly increase customers' energy needs. Numerous businesses are choosing to locate or expand in Georgia, and many of these businesses require a substantial amount of energy to support their operations. To put this in context, based on economic data available at the time of the 2022 IRP, the Company anticipated less than 400 MW of growth between the winter of 2023/2024 and the winter of 2030/2031. In contrast, based on data since the 2022 IRP, the Company's current projections reflect load growth

of approximately 6,600 MW through the winter of 2030/2031. Therefore, the Company must acquire additional capacity resources to help ensure it is able to continue supporting the energy needs of our customers and the state during this period of extraordinary economic growth.

Georgia Power's 2023 IRP Update Load and Energy Forecast projects extraordinary customer load growth stemming from the rapid economic development taking place in Georgia, which far exceeds the demand projected in the 2022 IRP. The Company's 2023 IRP Update Load Forecast reflects the increase in demand from the numerous new large load projects Georgia Power has been selected to serve as well as a considerable pipeline of future projects. These large load projects, which include manufacturers, the electric transportation industry, and data centers, are unprecedented in project size, volume, and pace of integration. Without a historical precedent for this extraordinary growth, these loads are not captured in the Company's standard forecasting process. Therefore, the Company developed a forecasting model to better capture the uncertainties related to new large loads, including state selection, electric service provider selection, project delays, and the materialization of load. With this additional information, the Company made certain external adjustments to the load forecast each year over the twenty-year planning horizon to account for the recent growth in projected load and incorporate the ramp rates for such large load additions by month and year.

The dramatic increase in projected load identified by the Company's load forecast has not only increased but accelerated the Company's capacity need. The load levels presented in the 2023 IRP Update reflect a projected capacity need in the winter of 2025/2026, which is a full three years earlier than what was anticipated in the 2022 IRP. Further, the magnitude of the projected capacity need in the winter of 2030/2031 has increased by 4,800 MW since the 2022 IRP.

So that it can meet the needs of a growing Georgia and continue to reliably serve customers, the Company plans to meet its winter capacity needs through a

combination of (i) resources that will be selected through the All-Source and Energy Storage System RFPs approved in the 2022 IRP, which will address the capacity needs beginning in the winter of 2028/2029; and (ii) the portfolio of resources presented in the 2023 IRP Update, which will address Georgia Power's capacity needs starting in the winter of 2025/2026. The 2023 IRP Update proposes a balanced portfolio of resources including power purchases and new build opportunities. These resources address the Company's short-term capacity needs and provide a foundation for the Company's long-term capacity needs and the continued transition of its generation fleet to cleaner resources.

Given the significance of the Company's increased projected loads and corresponding capacity needs, Georgia Power cannot wait to conduct the All-Source RFP or wait until the 2025 IRP to address these needs. The Company must act quickly to secure the critical resources necessary to meet the state's near-term energy needs. Georgia Power has adjusted and will continue to adjust as needed its pricing for new customer projects, consistent with existing tariff authority, to reflect the increased cost to serve those customers. All else being equal, we expect that the projected revenues associated with incremental load from these new customer projects will offset the costs of the resources requested in this filing and put downward pressure on our overall retail rates as we continue to provide clean, safe, reliable, and affordable power for all of Georgia Power's customers in the coming years.

Q. HOW IS YOUR TESTIMONY ORGANIZED?

A. The remainder of our testimony is organized as follows:

- Section II discusses Georgia Power Company's updated load and energy forecast.
- Section III discusses the Company's updated capacity needs.

- Section IV addresses the Company's proposed resource solutions, including the requests for certification of the PPAs between Georgia Power and Mississippi Power and between Georgia Power and Santa Rosa Energy Center LLC; approval to construct up to 1,000 MW of BESS; and approval to construct three CT resources at Plant Yates.
- Section V covers the Company's DER and demand response solutions, including the certification of two new customer-sited DER programs; certification of one new tariff-based demand response program; and certification for the expansion of one existing DSM demand response program.
- Section VI covers the customer impacts of the 2023 IRP Update.
- Section VII explains the Company's proposed Flex Capacity framework.
- Section VIII addresses the Transmission impacts of the 2023 IRP Update.

II. UPDATED LOAD AND ENERGY FORECAST

Q. PLEASE EXPLAIN THE SCALE AND PACE OF THE ECONOMIC GROWTH IN GEORGIA SINCE THE 2022 IRP.

A. Since the approval of the Company's 2022 IRP in July of 2022, Georgia's successful economic development efforts have added more than $24 billion in capital investment and more than 38,000 jobs to what was already a healthy pipeline of activity. Today, Georgia's economic development pipeline is more robust than ever, with record growth as companies are looking to locate or expand within the state. As explained in the 2023 IRP Update, this economic growth trend has been driven, in large part, by Georgia's recognition as one of the best places in the country in which to do business, and the state is attracting strong customer growth across residential, commercial, and industrial classes. This rapid economic expansion resulted in historic increases in the demand for energy at a scale and pace not previously experienced. New and expanding economic development projects can be seen in the investment and job creation in emerging industries like electric

transportation ("ET") manufacturing and its supplier base, as well as in more traditional industries, including the automotive, agricultural, information technology, and aerospace industries.

Q. HOW HAS THIS GROWTH CONTRIBUTED TO THE CHANGE IN GEORGIA POWER'S LOAD FORECAST?

A. Georgia Power's 2023 IRP Update Load Forecast, completed in September 2023, projects extraordinary load growth stemming from rapid economic development taking place in Georgia. The load growth identified in the 2023 IRP Update Load Forecast far exceeds that identified by the load forecast produced in August 2021 for the 2022 IRP. Through 2031, Georgia Power's projected winter peak demand is currently more than 5,900 MW greater than the winter peak demand projected in the 2022 IRP load forecast. For context, this increased demand is equivalent to almost 40% of the Company's winter peak demand for 2024 and is projected to materialize in less than a decade.

The Company initially identified a load increase when it created its Budget 2023 load forecast in August 2022 through its annual planning process. This forecast identified an increase of 1,100 MW through 2031 compared to the 2022 IRP filing. Although a sizable increase in load, this initial indication of increasing loads did not alter the 2029 capacity need year identified in the 2022 IRP. Because the increase in capacity was forecasted to occur in the existing capacity need year and would be addressed by the 2029-2031 All Source RFP, no action was necessary based on the Budget 2023 load forecast.

In January 2023, the Company began producing load forecast sensitivities with greater frequency than the annual load forecast to help better understand these changes in projected load and to further inform the Company's resource planning decisions. The load forecast sensitivity the Company developed in June of 2023 identified considerable increases in projected load. These increases first advanced the Company's capacity need to the end of 2026 or the winter of 2027. The

magnitude and accelerated timing of the Company's capacity needs identified following the summer 2023 load forecast sensitivities are the catalysts for the 2023 IRP Update, which is based on the updated load forecast produced in September 2023 ("2023 IRP Update Load Forecast"). The 2023 IRP Update Load Forecast projects a capacity need at the end of 2025, or the winter of 2026.

Q. WHY DID THE COMPANY BEGIN PRODUCING LOAD FORECAST SENSITIVITIES WITH GREATER FREQUENCY THAN THE ANNUAL LOAD FORECAST?

A. Georgia Power began producing load forecast sensitivities with greater frequency than the annual load forecast due to the significant increase in economic development projects in Georgia. The Company found it appropriate and necessary to evaluate projected load and capacity needs on a more frequent basis to plan and prepare for the rapid economic growth in Georgia and corresponding increased demand for energy. These load forecast sensitivities then allowed the Company to better understand the corresponding accelerated capacity needs as the revised load projections became available. This proactive approach helped Georgia Power plan for and address the growing energy needs of its customers and the state more effectively.

Q. PLEASE EXPLAIN HOW THE COMPANY DEVELOPED LOAD FORECAST SENSITIVITIES AND HOW THE COMPANY USED THAT INFORMATION PRIOR TO FILING THE 2023 IRP UPDATE.

A. The Company developed its load forecast sensitivities to assess the range and likelihood of future load growth from new large load customers. In developing the sensitivities, the Company used a probabilistic approach to develop external adjustments to its baseline commercial and industrial load and energy forecasts further described in this Section. These external adjustments are necessary to account for the unprecedented magnitude and speed of the economic development

now taking place in Georgia, which is not captured in baseline forecasts that rely on historical trends.

In developing the forecast model for large load projects, Georgia Power considers specific project details and acknowledges various uncertainties that are inherent in the forecasting process. The Company's model incorporates information for each large load project, including the projected commercial operation date ("COD"), the detailed year-by-year load trajectory (i.e., ramp-up), and the announced load or design capacity for the project, which aids in facility sizing and equipment procurement. The Company also classifies projects as Industrial or Commercial and segments projects based on specific business categories such as warehouse, battery manufacturing, cryptocurrency, data center, chemical processing, and solar panel manufacturing, thus further refining the data used to inform its forecast.

The Company's probabilistic model addresses several dimensions of the uncertainty that is inherent in large load projects, and several uncertainties are included in the model. For example, these uncertainty dimensions include:

- Location Decision Uncertainty, which recognizes that potential customers may choose to locate projects in a different state despite showing initial interest in Georgia;
- Provider Selection Uncertainty, which exists due to the competitive selection process for large load customers among multiple electric service providers;
- Execution Risk Uncertainty, which exists even after a customer selects Georgia Power as its electric service provider, because unforeseen circumstances, such as financial or economic conditions, may lead to project abandonment;
- Load Materialization Uncertainty, which acknowledges that the load announced by a customer is only an estimate of the customer's projected load, which may materialize at a lower level than initially anticipated; and

- COD Delay Uncertainty, which recognizes that the projected commercial operation date of a project may be delayed, thus resulting in the project's load materializing later than initially expected.

Prior to filing the 2023 IRP Update, external adjustments to the baseline load forecast have been standard practice and were used to account for energy and peak demand resulting from new or ongoing uses that are not fully embedded in historical data or explicitly captured by our models. The Company assesses the need for external load adjustments when large customers are announced, typically introducing them when these customers bring a new line of business to the state or when the implied growth from our models is insufficient to represent the addition of the new load.

Q. WHAT FACTORS ARE CONTRIBUTING TO THE RAPID ECONOMIC DEVELOPMENT TAKING PLACE IN GEORGIA?

A. There are several factors contributing to this rapid economic development. For example:

- **Government Policies**: State and local government policies promoting economic development, including incentives for businesses to relocate or expand in Georgia, have contributed to the state's economic development.
- **Attractive Business Climate**: Georgia is a top state in which to do business, with competitive tax structures, a skilled workforce, and strong infrastructure. These factors have attracted a wide range of industries to the state, including technology, manufacturing, logistics, and healthcare.
- **Investment in Infrastructure**: Significant investments in infrastructure, including transportation, utilities, and digital connectivity, make Georgia an attractive location for businesses.
- **Population Growth**: Georgia's population is growing, leading to an increased demand for goods and services and driving economic development.

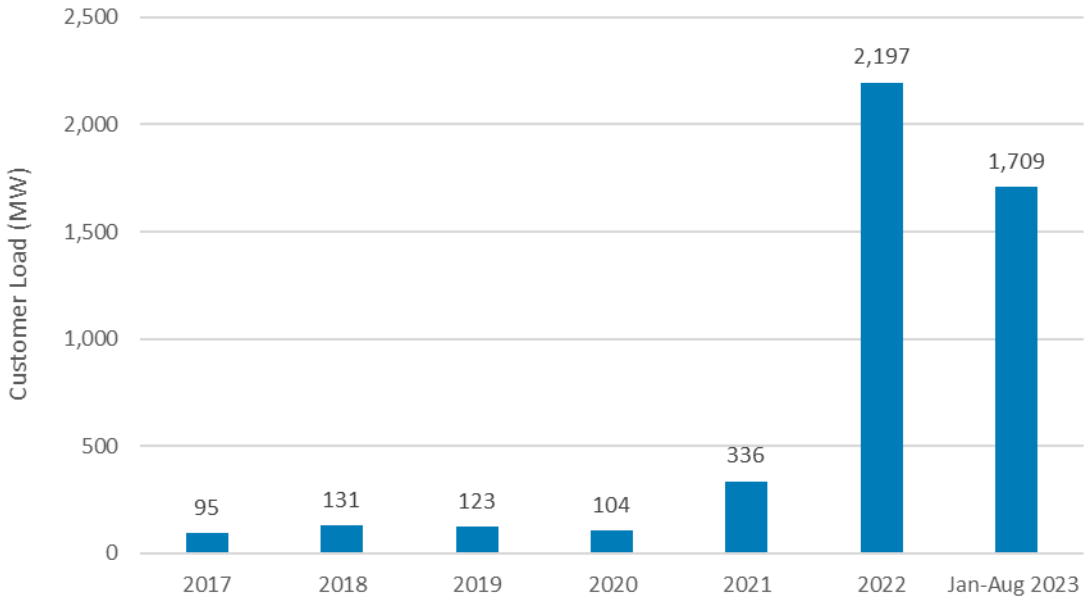
- **Emerging Industries**: The growth of emerging industries, such as renewable energy, electric vehicles, and data centers, has contributed to economic development.

Government policies creating an attractive business climate and promoting infrastructure investment are the foundation that attracts emerging industries, jobs, and population growth. The resulting economic growth has significantly increased the demand for energy, thereby driving the 2023 IRP Update.

Q. HOW DOES THE MAGNITUDE OF NEW ECONOMIC DEVELOPMENT PROJECTS THAT GEORGIA POWER IS BEING ASKED TO SERVE COMPARE TO HISTORICAL NORMS?

A. There has been a dramatic increase in the size of economic development projects Georgia is attracting to the state. Prior to 2021, on average, the Company was selected to serve approximately 100 MW of large load economic development projects per year. Then, in 2021, the Company was selected to serve 336 MW, or three times this historical average. This number increased substantially in 2022, during which the Company was selected to serve 2,197 MW, or twenty-two times its historical average. Through August of 2023, the Company had already been selected to serve more than 1,700 MW of large economic development projects. Figure 1 below illustrates the increase in economic development projects requesting electric service from Georgia Power.

Figure 1: New Large Load Customers Selecting Georgia Power by Year



These large load economic development projects correspond to the robust economic growth and influx of new businesses in Georgia, including manufacturers, the EV industry, data centers, and other businesses. Significantly, many of these new customers are bringing load to Georgia Power's system that falls well outside of historical norms. Some of these customer loads surpass 1,000 MW each. Moreover, the energy profiles for many of these new customers have high load factors and require a substantial amount of generation and consistent energy delivery around the clock.

Q. WHY DIDN'T THE LOAD AND ENERGY FORECAST USED IN THE 2022 IRP CAPTURE THE BOOM IN ECONOMIC GROWTH THAT PROMPTED THE 2023 IRP UPDATE?

A. Consistent with the forecasting methodologies used in prior IRPs, the Company's 2022 IRP Load Forecast was appropriately informed by projections based on historical trends and foreseeable economic growth. The forecast could not project load additions for industries without historical data, nor could it have captured the

extraordinary economic growth and increased load that has taken place since the 2022 IRP. Nothing in the Company's or state's history would have predicted load growth of this magnitude or that such growth would occur so rapidly.

Q. HOW DOES THE COMPANY ACCOUNT FOR THE LARGE INFLUX OF ANTICIPATED LOADS IN ITS FORECAST?

A. The Company accounts for the addition of large loads by making external adjustments to its Load and Energy Forecast. This process is necessary because the economic development growth associated with these large loads would not otherwise be captured in the historical trends that underlie the Company's base forecast. While the use of an external adjustment for large load additions is not new, the Company recently had to revise its methodology for calculating and applying the adjustments because of the extraordinary size of the large loads projected on the electric system.

Q. PLEASE DESCRIBE THE COMPANY'S METHODOLOGY FOR ADJUSTING THE LOAD AND ENERGY FORECAST IN THIS CASE.

A. As described in the Load and Energy Forecast Technical Appendix, the external adjustment process involves several steps:

1. **Known Project Inputs**: For each large load customer choice project the Company evaluated and included in the forecast update, the customer requiring electric service provided the following information: COD; ramp-up; announced load; class; and segment.
2. **Modeling Project Uncertainty**: As described previously, each customer choice project contains multiple dimensions of uncertainty, which must be considered in developing a forecast. These uncertainties include the customer's state selection, electric provider selection, project delays, and load materialization. Based upon its knowledge and experience, the Company develops a probability analysis for each point of uncertainty. To account for

these uncertainties, the Company then uses a probabilistic approach to determine the success or failure of an individual customer project.

3. **Incorporating the Model**: The Company incorporates three probability distributions (project delay, actual/announced load percentage, and project success/failure) into the expected ramp-up schedule for a project. This involves shifting the COD by a COD delay random variable, scaling the shifted year-by-year load trajectory by the actual/announced load percentage random variable, and multiplying the shifted and scaled year-by-year load trajectory by the Bernoulli 0/1 random variable that represents state selection, electric provider selection and completion rate.
4. **Modeling the Portfolio**: The Company uses a tiered approach to define the coefficients that describe the interaction among projects in the customer choice portfolio. This approach is driven by the class and segment of the projects instead of being defined one by one.
5. **Model Implementation**: The probabilistic approach is implemented in Excel with a third-party add-in called @Risk, which allows for Monte Carlo simulation and analysis.

This approach allows the Company to adjust the load forecast to account for the large influx of anticipated load in a way that is both realistic and mathematically rigorous, allowing the Company to plan for a probable amount of customer choice load and avoid overestimating load additions that could add unnecessary capacity to the electric system.

Q. PLEASE EXPLAIN HOW THE EXTERNAL ADJUSTMENTS ARE DETERMINED AND APPLIED TO THE BASELINE FORECAST.

A. The external adjustment involves several key steps to refine the baseline load forecast. First, the Monte Carlo model generates a distribution of megawatt (MW) outcomes for the Company's load portfolio by quarter. Employing a probabilistic approach, this distribution reflects the range and likelihood of future load growth

from new large load customers. Next, the total portfolio MW is allocated to each individual project, to capture the contribution of each project to the overall load portfolio outcome. This step ensures that the unique characteristics and scale of each project are considered in the adjustment.

To translate individual project contributions into a form that is compatible with the Company's baseline energy forecast, the contributions are converted to an energy metric by applying load factor assumptions specific to each project. The resulting energy figures represent the external adjustment (i.e., the additional load attributable to new projects). The calculated external adjustment is then added to the baseline forecast to determine the total load the Company must serve.

Q. DOES THE COMPANY EXPECT ITS LOAD PROJECTIONS TO CHANGE?

A. The Company's load projections will change as economic conditions change. Current economic conditions suggest that Georgia continues to be attractive to new firms. By incorporating the new data and methodologies in this filing, the Company will be able to more closely follow the changing conditions of large loads and incorporate their impacts more effectively.

III. UPDATED CAPACITY NEEDS

Q. PLEASE IDENTIFY THE PRIMARY DRIVERS IMPACTING THE COMPANY'S UPDATED CAPACITY NEEDS AND CORRESPONDING REQUESTS IN THIS CASE.

A. Georgia Power's requests are primarily driven by three factors: (1) an increased and accelerated demand for electricity; (2) a decrease in the availability of electricity supply from existing generation resources in the wholesale market; and (3) the time required to build or buy energy from new resources to meet capacity needs arising as early as 2026. The Company must carefully manage these driving forces in a rapidly evolving climate.

The increased and accelerated demand for electricity is the primary driver behind the need for capacity and the Company's request for additional resources in the 2023 IRP Update.

The second driver, the decreased supply of electricity, is related to the limited amount of electric generation capacity available in the wholesale market. Several other utilities in the Southeast recently concluded or are actively conducting RFPs seeking additional capacity from wholesale assets in the region. Should these utilities identify any available capacity and procure it, this will further reduce Georgia Power's opportunity to procure wholesale capacity to meet the needs of its customers. Notably, the Company was one of the first utilities to the solicit market when it procured and certified over 2,300 MW of wholesale market capacity in the 2022 IRP, well in advance of tightening market conditions.

The third driver is the limited time available to procure or construct the resources needed to meet customers' capacity needs. Georgia Power's RFP process typically takes two to two-and-a-half years to identify, evaluate, and select capacity resources. Even if an RFP was issued immediately and concluded within that timeframe (i.e., as early as November 2025), only PPAs for existing wholesale generation assets could meet capacity needs in 2026. And that assumes such capacity resources remained available for the entirety of the lengthy RFP process. Any new-build resources selected through such an RFP would need to be constructed within one year to meet capacity needs, which is not a feasible timeline for construction.

Q. CAN GEORGIA POWER'S RESERVE MARGIN PROVIDE SUFFICIENT CAPACITY TO MEET THE INCREASE IN CUSTOMERS' NEEDS?

A. No. The Company's reserve margin accounts for various operational uncertainties, including weather, load forecast, unit performance, and market availability. The load forecast component in the 2021 Reserve Margin Study, filed in support of the Company's 2022 IRP, appropriately reflected a normal level of uncertainty in the

demand of both existing and new customers. This uncertainty was considered in determining the target reserve margin. However, the load forecast uncertainty component of the 2021 Reserve Margin Study was never intended to reflect the significant increase in demand being driven by the extraordinary economic growth addressed by the 2023 IRP Update. Therefore, the target reserve margin established in the 2022 IRP does not provide sufficient reserves to address the substantial load growth projections presented in the 2023 IRP Update.

Q. DID GEORGIA POWER CONSIDER WHETHER ITS INCREASED CAPACITY NEED COULD BE MET WITH MARKET RESOURCES?

A. Yes. The Company actively participates in the wholesale energy market, conducts numerous RFPs, and just completed a Request for Information ("RFI") targeting the wholesale market. The Company's last Capacity RFP resulted in contracts with six existing facilities that were approved in the 2022 IRP. These contracted resources will continue to support the energy needs of Georgia Power's customers during this period of economic growth.

The recently completed RFI, issued in September 2023, gathered market information regarding the availability of existing capacity resources to help address the Company's accelerated capacity need for years 2026 through 2028, as well as the expanded capacity needs for years 2029 through 2031, which are to be addressed in the All-Source RFP approved in the 2022 IRP. In response to its RFI, the Company received 44 unique submissions, 32 of which were mutually exclusive opportunities that met resource qualifications sought by Georgia Power. Notably, only two of the 44 submissions were existing facilities. Neither existing facility has capacity available in the winter of 2025/2026 through the winter of 2027/2028. The Company's knowledge of the wholesale market, as confirmed by the RFI, indicates that existing market resources are not sufficient to address the capacity need identified in the 2023 IRP Update.

Q. HOW DO THE RESULTS OF GEORGIA POWER'S RFI IMPACT ITS REQUEST?

A. As demonstrated by the Company's RFI Summary Report included in Georgia Power's Supplemental Filing made December 4, 2023, there is no indication from the market that there are additional existing resources that can meet the Company's capacity needs in the winter 2025/2026 to winter 2027/2028 timeframe. The RFI results support the Company's resource plan identified in the 2023 IRP Update.

Q. CAN THE COMPANY LEVERAGE THE ALL-SOURCE RFP TO MEET THE CAPACITY NEED IDENTIFIED IN THE 2023 IRP UPDATE?

A. No. The All-Source RFP cannot acquire resources quickly enough to meet capacity needs identified for the winter of 2025/2026. As noted previously, the RFP process typically takes two to two-and-a-half years from selection of the independent evaluator to the certification of resources. Even if an RFP could be issued immediately and completed within two years (e.g., by November 2025), only PPAs for existing wholesale generation assets would be able to meet capacity needs in the winter of 2025/2026. Moreover, this assumes those resources would be both existing and available, as well as economical and reliable. As demonstrated by the results of the Company's recent RFI, there are not sufficient existing resources available in the wholesale market to meet the Company's resource needs identified in the 2023 IRP Update. If the Company relied solely on the RFP process to procure resources, it would be unable to meet its capacity needs in the timeframe addressed in this 2023 IRP Update and would be limited in its ability support the continued economic development of the state. The All-Source RFP that was approved in the 2022 IRP will help the Company address its increased capacity needs in 2029-2031. Notably, the Company plans to increase the number of MW it will seek to procure

in the upcoming All-Source RFP to address the increased capacity needs in the 2029-2031 timeframe.

Q. IS THE COMPANY GENERALLY REQUIRED TO PROCURE NEW SUPPLY SIDE RESOURCES THROUGH AN RFP?

A. Yes. However, as described above, the standard RFP process will not procure the capacity needed to meet the energy needs of our customers quickly enough. The Commission's rules contemplate that such a scenario might occur. Accordingly, and consistent with the Commission's rules, the resource requests included in this 2023 IRP Update rely on several of the Commission's approved exceptions to the RFP process. These exceptions are more fully addressed later in our testimony.

Q. PLEASE EXPLAIN WHY THE COMPANY MUST REQUEST ADDITIONAL GENERATION RESOURCES NOW INSTEAD OF WAITING UNTIL THE 2025 IRP.

A. Time is of the essence — To meet the capacity need arising in the winter of 2025/2026, the Company must take reasonable and appropriate steps to procure resources that can be available for use by the end of 2025. In the 2022 IRP, the Company projected needing additional capacity at the end of 2028. The 2022 IRP Order approved a plan – which authorized the Company to conduct several RFPs – that would enable the Company to procure the needed generation resources in time to meet the winter of 2028/2029 capacity need. The accelerated load growth that has occurred since the 2022 IRP has resulted in the need to procure capacity for the winter of 2025 /2026 (i.e., December 2025 through February 2026) – three years earlier than the winter of 2028/2029, as projected in the 2022 IRP.

Q. PLEASE ADDRESS POTENTIAL CHALLENGES OR RISKS ASSOCIATED WITH MEETING THE INCREASED CAPACITY NEED.

A. Potential challenges and risks associated with meeting the increased capacity need identified in the 2023 IRP Update include the following:

- **Limited Resource Availability**: There is unlikely to be enough existing firm generation available to meet the increased demand for energy by the winter of 2027/2028. While the Company's procurement of existing resources secures some capacity, it does not fill or alter the need for new capacity needed to serve customers.
- **Competition for Resources**: Other utilities are also navigating the need for additional capacity based on potential load growth, seeking replacement capacity for retiring coal units, and adding resources to meet their newly established or increased winter target reserve margins. This competition limits the availability of market resources to meet Georgia Power's needs.
- **Reliance on Third Parties**: The Company cannot rely solely on third-party independent power producers, who do not have an obligation to serve, to meet its customers' energy needs. Consistent with Commission policy, the Company must maintain an appropriate balance between Company-owned resources and purchased power to ensure the reliability of the electric system and meet the energy needs of the customers it is obligated to serve.
- **Transmission Constraints**: Limitations on available transmission capacity could also limit the timeframe in which the Company can leverage existing resources or deploy new resources. Therefore, the Company must carefully plan and coordinate the addition of new transmission improvements to mitigate these constraints.
- **Regulatory and Policy Changes**: Changes in energy policies or regulations could impact the Company's plans and operations. For example, changes in environmental regulations could affect the operation of certain types of power plants in the future.

- **Technological Challenges**: The integration of new technology, such as battery storage systems, can present technical challenges and require significant investment.
- **Load Forecast Uncertainty**: While the Company's load forecasts are based on the best available information, they cannot predict the future with absolute certainty, and actual demand could be higher or lower than projected.

Q. WHAT IS THE COMPANY'S PLAN TO ADDRESS THE INCREASED AND ACCELERATED CAPACITY NEEDS, AND ASSOCIATED RISKS, IDENTIFIED IN THE 2023 IRP UPDATE?

A. The Company developed a well-balanced, reasonable, and diversified plan that ensures it continues providing reliable and affordable power to its customers. The 2023 IRP Update proposes to leverage the Commission Rules' RFP exemptions to acquire available capacity on the Southern Company system and from the constrained existing capacity and energy market, utilize existing transmission interconnections for newly proposed BESS resources, identify transmission solutions to enable resource deployment, and to construct new supply-side assets to ensure capacity is available by the years needed and to reduce reliance on third parties. The diverse portfolio includes both thermal and storage resources in light of potential technological and policy challenges, and the plan creates or modifies Distributed Energy Resource ("DER") and demand-side programs that can mitigate quick load ramps associated with economic development load. The resources being proposed by the Company in the 2023 IRP Update are described more fully below.

IV. PROPOSED RESOURCES

Q. CAN THE COMPANY SUPPORT THE RAPID ECONOMIC DEVELOPMENT AND CUSTOMER DEMAND IN GEORGIA?

A. Yes. The Company is well positioned to continue providing the resources and infrastructure required to power Georgia's robust economy, including the capacity

required to support continued economic development. With the support of this Commission, the Company has a well-established record of meeting the energy needs of its customers and providing them with clean, safe, reliable, and affordable energy. Georgia's constructive regulatory framework, as overseen by the Commission, provides the necessary foundation for the Company to meet the energy needs of our state during this period of extraordinary economic growth.

The 2022 IRP established a strong base of 1500-1600 MW of capacity length to meet all current and contracted customer demands in the near term. Further, the BESS projects approved in the 2019 IRP (Mossy Branch) and in 2022 (McGrau Ford) will provide valuable development and operational experience with this burgeoning technology. Finally, the Company's extensive planning and operational experience provide the knowledge and tools necessary to keep pace with growing customer demand and Georgia's thriving economy.

Q. PLEASE IDENTIFY THE RESOURCES PROPOSED IN THE 2023 IRP UPDATE AND EXPLAIN HOW EACH RESOURCE WILL HELP MEET THE CAPACITY NEEDS IDENTIFIED BY GEORGIA POWER'S UPDATED LOAD FORECAST.

A. Georgia Power is proposing the following resources to meet the capacity needs associated with its revised load forecast:

- **Purchases of Capacity and Energy**: Georgia Power seeks to certify PPAs with Mississippi Power and a market resource, Santa Rosa Energy Center. These agreements will provide immediate additional capacity and energy to meet the growing demand.
- **BESS**: Georgia Power proposes to develop, own, and operate up to 1,000 MW of BESS and/or BESS plus Solar at various sites, including two of Georgia's military bases. These systems will provide additional capacity and help to balance the grid.

- **Simple Cycle CT Resources**: The company proposes to develop, own, and operate up to 1,400 MW of simple cycle CT resources at Plant Yates. These resources will provide additional capacity and help to meet peak demand.

Together, these projects are designed to meet Georgia Power's updated load forecast and capacity needs, ensuring the Company can continue to provide reliable and affordable power to its customers.

Q. DOES THE COMPANY CONTINUE TO SUPPORT THE FLEET TRANSITION PROPOSED IN THE 2022 IRP?

A. Yes. The Company will continue to responsibly transition its generation fleet to cleaner resources while maintaining reliable and affordable electric service for customers. The 2023 IRP Update supports this transition by focusing on resources that meet the Company's near-term capacity need and enable the Company to provide reliable and affordable electric service.

The Company remains optimistic about the future of renewable resources, as well as the prospects of the Inflation Reduction Act ("IRA") and its potential to reduce the cost of new renewables for customers. As consistently demonstrated by the Company's expansion planning analysis, new solar generation remains economically attractive and will continue to be considered as a generation resource in future IRP cycles. This 2023 IRP Update is focused on meeting the capacity needs associated with Georgia's rapid economic growth, and these capacity needs require a level of reliability and resilience that cannot be met with solar resources alone. Therefore, the Company's 2023 IRP Update seeks firm capacity resources while reaffirming that renewables remain a crucial component of the Company's long-term plans.

Regarding the future of renewable energy, the renewable energy expansion plans developed for the 2023 IRP Update suggest the Company could economically add up to approximately 10,000 MW of new renewable resources by 2035, which is

significantly more than the 6,000 MW projected in the 2022 IRP. Notably, the Company's continued expansion of BESS and DER resources, such as those proposed in the 2023 IRP Update, are essential to ensuring that the grid remains reliable and resilient while the Company continues adding renewable resources to its generation mix.

Q. WHY ARE COMPANY-OWNED RESOURCES A CRITICAL PART OF RESPONDING TO THE NEEDS IDENTIFIED IN THE 2023 IRP UPDATE.

A. Georgia Power cannot rely solely on existing market capacity to satisfy the Company's growing capacity needs. As noted previously, there are not enough market resources to meet the capacity needs nor is there enough time to conduct an RFP. Thus, Company-owned resources are essential to the Company's ability to meet its capacity needs and to continue providing customers with reliable electric service. While the Company supports the selection of market resources through the RFP process for the benefit of customers, market participants selected through that process are not obligated to serve Georgia Power's customers and are not able to address the Company's capacity needs on the accelerated timeline identified in the 2023 IRP Update. So that it can continue providing its customers with reliable service and meet the timelines of customers' needs, Georgia Power must develop new resources in accordance with the RFP exceptions in the Commission's Rules in addition to procuring resources through the typical RFP process. Moreover, to ensure a reliable and efficient transition of the generation fleet, it is critical that the Company maintain a diverse resource portfolio that includes market resources, Company-owned resources, and a balance of resource technologies.

Q. HOW HAS THE COMMISSION HISTORICALLY ADDRESSED THE NEED FOR COMPANY OWNERSHIP?

A. Longstanding Commission policy requires Georgia Power to own at least 70% of its supply-side resources to ensure system reliability and sufficient Commission oversight of the resources serving customers. The resource plan set forth in the 2023

IRP Update is consistent with this Commission policy and continues to provide an appropriate balance between Company-owned resources and contract PPAs from the wholesale market. Even if Georgia Power was able to contract for all the capacity needed to serve customers through the winter of 2030/2031 via PPAs, the number of Company-owned resources serving customers would fall below 70% as early as the winter of 2026/2027 and would decrease to approximately 56% by the winter of 2030/2031. Such an unprecedented decrease in the percentage of Company resources dedicated to serving customers would be inconsistent with Commission policy and present system reliability risks. Therefore, in the 2023 IRP Update, the Company is notifying the Commission that Company-owned capacity resources will fall below the minimum percentage required by Commission policy if the Company's updated capacity need is met only through PPAs. As such, the Company respectfully requests Commission approval of the Company-owned resources identified in the 2023 IRP Update so the Company can maintain the appropriate level of Company-owned resources set by Commission policy in the interests of system liability and sufficient Commission oversight of the resources serving Georgia Power's customers.

Q. WHY IS THE COMPANY REQUESTING A WAIVER OF THE COMMISSION'S RFP RULE?

A. The duration of the RFP process and the limited number of existing resources on the wholesale market prevent the Company from relying on the RFP process to acquire the capacity needed to meet the increased energy needs of customers identified in the 2023 IRP Update. Therefore, the Company is requesting Commission approval to develop, procure, or purchase the capacity and energy from the new supply-side capacity resources identified above under three exceptions to the RFP process set forth under Commission Rule 515-3-4-.04(f). First, there is an exception for supply-side capacity resources of extraordinary

advantage that require immediate action.[1] Second, the Commission has the authority during an IRP proceeding to certify new supply-side resources without first requiring an RFP process.[2] Third, when the Company nears or finds that it would fall below the minimum percentage of self-owned capacity (70%), the Commission rules require the Company to inform the Commission of this eventuality in advance of the RFP process, at which time the Commission may suspend the RFP requirements and provide guidance to the Company on how to proceed.[3]

As previously discussed, time is of the essence. An RFP process cannot be completed quickly enough to meet the capacity needs identified in the 2023 IRP Update, and there is not enough existing capacity available in the wholesale market to meet the cumulative need of 2,601 MW by the winter of 2027/2028. The procurement of resources pursuant to the aforementioned exceptions will facilitate the timely deployment of supply-side resources needed to serve customers, while mitigating the risks that the market either cannot provide enough capacity or will not offer enough firm and dispatchable resources to reliably serve customers. Accordingly, the Company requests that the Commission approve the supply-side resources in its 2023 IRP Update pursuant to the RFP Rule exceptions deemed applicable and appropriate by the Commission.

Q. ARE THE CAPACITY RESOURCES PROPOSED IN THE 2023 IRP UPDATE ECONOMICAL AND RELIABLE?

A. Yes. The resources proposed by the Company are both economical and reliable. The proposed natural gas resources have a fuel supply plan that incorporates the necessary firm gas transportation or oil capacity to support reliable operation. In

[1] Commission Rule 515-3-4-.04(3)(f)(3).
[2] Commission Rule 515-3-4-.04(3)(f)(6).
[3] Commission Rule 515-3-4-.04(3)(f)(7).

the case of Plant Yates Units 8-10, on-site fuel storage is available, improving the reliability and resilience of the resources by reducing the reliance on just in time fuel supply. The proposed BESS additions can provide firm capacity with the ability to charge from both the grid and adjacent solar facilities. The Mississippi Power PPA provides firm capacity supported by the diverse portfolio of resources within Mississippi Power's system. Each of these options has undergone a detailed economic ranking analysis as shown in the Technical Appendix to the IRP Update. This analysis provides detailed cost and benefit information demonstrating the cost-effectiveness of each option.

A. Certification of the Mississippi Power PPA

Q. PLEASE EXPLAIN THE COMPANY'S REQUEST FOR CERTIFICATION OF A PPA WITH MISSISSIPPI POWER.

On October 11, 2023, Georgia Power and Mississippi Power executed a PPA for the sale of 750 MW of capacity and energy from Mississippi Power to Georgia Power for the term of January 1, 2024, through December 31, 2028. Per the order issued in Docket No. 2018-AD-145 before the Mississippi Public Service Commission, Mississippi Power must retire approximately 950 MW of capacity by the end of 2027 or show with detailed evidence why continued operation of the resources is in the best interests of its customers.[4] While this capacity is currently available for Georgia Power customers in times of need due to reserve sharing within the Southern Company pool, Mississippi Power planned to retire some of that capacity by the end of 2023 and was actively remarketing the other capacity to be sold off-system. These actions would have removed this capacity from the

[4] https://www.psc.state.ms.us/InSiteConnect/InSiteView.aspx?model=INSITE_CONNECT&queue=CTS_ARCHIVEQ&docid=655509

Southern Company pool, in which case it would not otherwise have been available to serve Georgia Power customers.

By purchasing 750 MW from Mississippi Power through this PPA, Georgia Power ensures that this capacity will remain within the Southern Company pool and provide dedicated, reliable, market-priced capacity and energy to Georgia Power's customers. The PPA obligations can be met by any resources available to Mississippi Power. A certification application for the PPA between Georgia Power and Mississippi Power is found in Attachment A of the 2023 IRP Update, and the executed PPA is provided in the Technical Appendix.

Q. WHAT IS THE COMPANY'S PLAN FOR THE CAPACITY PURCHASED FROM MISSISSIPPI POWER PRIOR TO GEORGIA POWER'S YEAR OF NEED?

A. Southern Wholesale Energy ("SWE"), on behalf of Georgia Power, will attempt to remarket this capacity for years prior to the winter of 2025/2026. The Company has already sold 500 MW to a regional electrical service provider for January 1, 2024, through September 30, 2025. To the extent the Company is unable to remarket all of the capacity within this period and recover all the incremental costs, the Company requests regulatory asset treatment to defer the capacity and non-fuel energy payments made under the PPA, including additional sum, net of the wholesale capacity and non-fuel revenues from any remarketed capacity sales from January 1, 2024, through December 31, 2025, including this executed system sale to a regional electrical service provider during that time, for recovery in the next base rate case.

Q. PLEASE EXPLAIN THE COMPANY'S REQUEST FOR AN ADDITIONAL SUM ON THIS PPA.

A. Pursuant to the IRP Statute, the Company is entitled to an additional sum for long term power purchases. When calculating the additional sum, the statute requires

that lost revenues, changed risks, and an equitable sharing of benefits between the utility and its retail customers be considered. For the Mississippi Power PPA, as well as the Santa Rosa PPA below, the Company requests an additional sum of $3/kW-year, consistent with the Commission-approved additional sum amounts applied to the Capacity PPAs certified in the 2022 IRP.

B. Certification of the Santa Rosa PPA

Q. PLEASE DESCRIBE THE SANTA ROSA ENERGY CENTER.

A. The Santa Rosa Energy Center is a combined-cycle resource located in Pace, Florida. The Santa Rosa PPA offers several benefits for the Company and customers. Due to its location and existing grandfather rights, no additional transmission improvements or transmission service is needed for power to be delivered from the Santa Rosa Energy Center to the Southern Company System. In addition, System Operators have purchased energy and capacity from the Santa Rosa Energy Center in the past and are familiar with the facility and seller.

Q. PLEASE EXPLAIN THE COMPANY'S REQUEST FOR CERTIFICATION OF A PPA WITH SANTA ROSA ENERGY CENTER LLC.

A. On October 22, 2023, Georgia Power and Santa Rosa Energy Center LLC executed a PPA for the sale of up to 230 MW of capacity and energy. Capacity and energy will be available beginning in the first of the month following Commission approval and will continue through December 31, 2028. This agreement allows Georgia Power to take advantage of the near-term availability of this resource to address the capacity needs identified in the 2023 IRP Update. The short-term nature of this PPA also allows the Company to bridge its capacity needs until the All-Source Capacity RFP procures resources for the winter of 2028/2029 and beyond. A certification application for the PPA between Georgia Power and Santa Rosa Energy Center LLC is found in Attachment B of the 2023 IRP Update, and the executed PPA is provided in the Technical Appendix.

Q. WHAT IS THE COMPANY'S PLAN FOR THE CAPACITY PURCHASED FROM SANTA ROSA ENERGY CENTER PRIOR TO 2026?

A. As with the Mississippi Power PPA, SWE, on behalf of Georgia Power, will attempt to remarket the Santa Rosa Energy Center capacity for the years prior to the winter of 2025/2026. To the extent the Company is unable to remarket all of the capacity within this period and recover all the incremental costs, the Company requests regulatory asset treatment to defer the capacity and non-fuel energy payments made under the PPA, including additional sum, net of any wholesale capacity and non-fuel revenues from any remarketed capacity sales from January 1, 2024 through December 31, 2025, for recovery in the next base rate case.

C. BESS

Q. PLEASE DESCRIBE THE COMPANY'S REQUEST IN THIS IRP UPDATE WITH RESPECT TO BESS.

A. Georgia Power is proposing new BESS projects to provide capacity as early as the winter of 2026/2027. Specifically, the Company proposes to add 178 MW of 4-hour duration lithium-ion BESS to existing Company-owned solar facilities at Robins and Moody Air Force Bases and 200 MW of BESS plus 200 MW of solar at a new site. Additional details regarding the specific proposed BESS projects and the estimated cost of each resource are found in the Technical Appendix.

Q. WHY IS THE COMPANY PROPOSING TO DEVELOP BESS PROJECTS AT ROBINS AND MOODY AIR FORCE BASES?

A. The proposed BESS projects at Georgia Power's Robins and Moody Air Force Base solar facilities will leverage existing interconnection rights and transmission deliverability. These resources can be charged by the Company's largest owned solar resources located adjacent to each site but may have opportunities to be charged by the grid depending on the availability of firm transmission capacity. As

such, these projects save time and avoid additional capital investment that otherwise would be required to construct interconnection facilities and transmission system upgrades to charge and discharge the BESS. The proposed BESS resources will also optimize energy savings by shifting the energy output of the facilities from hours with a relatively low system marginal cost to hours with a relatively high system marginal cost. The BESS will also firm up the winter planning capacity of the existing solar facilities at both sites by storing energy that can then be dispatched by system operators to benefit the grid. Without BESS, the winter planning capacity for the solar resources at each site is 10% of the nameplate capacity of each facility. With the BESS, each facility can provide 100% of the solar nameplate capacity to meet winter capacity needs, thus maximizing the utilization of the existing solar resources.

Q. PLEASE DESCRIBE THE COMPANY'S PROPOSED BESS PLUS SOLAR PROJECT.

A. The proposed BESS plus solar project will be comprised of 200 MW of BESS plus 200 MW of new solar. The proposed BESS plus solar project is projected to be online by the winter of 2026/2027. The BESS will be initially charged by the accompanying new solar resource but may have opportunities to be charged by the grid depending on the availability of firm transmission capacity. As with the BESS proposed for the Robins and Moody Air Force Base projects, the BESS plus solar project can leverage existing interconnection and transmission system capabilities that mitigate delays associated with long-lead time transmission system improvements.

Q. IS THE COMPANY PURSUING ANY OTHER BESS OPPORTUNITIES?

A. Yes. The Company is also pursuing additional BESS opportunities at facilities that may have transmission capacity available as early as the winter of 2026/2027. This includes standalone BESS, BESS added to existing solar facilities, or BESS plus charging solar. Since the availability of additional transmission capacity could limit

the timeframe in which the Company can deploy new resources, the Company requests the flexibility to add up to 1,000 MW total of BESS resources to be online by the end of 2027, inclusive of 378 MW for the proposed Robins, Moody, and BESS plus solar projects. This added flexibility will allow the Company to utilize resources that provide the best value to Georgia Power customers. When the Company identifies additional BESS project options, the Company will return for Commission approval and certification.

Q. WHY IS THE COMPANY PURSUING BESS AS A RESOURCE?

A. The time to construct BESS is shorter than other types of generation and, therefore, can be more quickly deployed to help meet the earlier capacity needs identified in the 2023 IRP Update. Moreover, the Company's Resource Mix Study, provided in the Technical Appendix, selects BESS as an economically optimal resource beginning in the winter of 2026/2027, and selects solar as an economically optimal resource beginning in the winter of 2027/2028. The Company-owned BESS proposed in the 2023 IRP Update would contribute to the significant amount of capacity required for the Company to maintain at least 70% utility ownership of the resources serving Georgia Power's customers, consistent with Commission Policy.

Q. HOW DOES THE COMPANY PROPOSE TO TREAT THE BESS RESOURCES FROM A RATEMAKING PERSPECTIVE?

A. The Company intends to pursue available tax credits through the IRA and similar incentives for the proposed BESS projects and to pass those benefits to customers. If these BESS requests are denied by the Commission, the Company requests any development costs not useful or transferable to other projects to be deferred to a regulatory asset with the amortization period of the recovery to be determined in the next base rate case.

D. CT Resources

Q. PLEASE DESCRIBE THE COMPANY'S CT RESOURCE REQUEST IN THIS IRP UPDATE.

A. The Company proposes to construct three advanced, dual-fuel CTs at Plant Yates. Advanced gas turbines also allow for the incorporation of catalyst control systems to lower emissions significantly compared to previous generations of the technology. In addition, the Company proposes to locate the CTs at Plant Yates to leverage current infrastructure and operational efficiencies.

The three advanced gas turbines proposed at Plant Yates would provide between 1,000 to 1,400 MW of capacity, depending on the fuel source being utilized, providing higher output and greater efficiency than previous generations of simple cycle CT designs. When gas is available, the units would provide up to approximately 1,400 MW of capacity. If gas is unavailable, the units could run on oil and provide approximately 1,000 MW to 1,100 MW of capacity, with on-site oil storage capability to provide reliability and resiliency benefits to the electric system. Based on the results of the transmission screening analyses provided in the Technical Appendix of the 2023 IRP Update, the total firm output of the proposed CTs will be limited to 600 MW until transmission improvements are completed in the summer of 2028. Additional details regarding the proposed dual-fuel simple cycle CT resources and estimated costs are found in the Technical Appendix of the 2023 IRP Update.

Q. WHY IS THE COMPANY PROPOSING THESE CT RESOURCES RATHER THAN PROPOSING TO BUILD MORE ENERGY STORAGE RESOURCES?

A. As evidenced in recent IRPs as well as the 2023 IRP update, the Company remains very supportive of energy storage and anticipates the continued growth of that technology. However, to preserve system reliability and resilience for all customers

during all hours, the Company needs a diverse portfolio of dispatchable resources. During extended periods, or multi-day events, of limited solar generation, such as during rainy periods or cloudy days, CTs will provide dispatchable generation that is not limited to 2- or 4-hour durations, thus supporting system reliability and resilience. These resources complement battery storage resources, which rely on generation from other assets to charge, by providing dispatchable peaking power when it is needed to meet customers' energy needs. As energy storage resources continue to grow as a percentage of Georgia Power's portfolio, and to support renewable integration, the Company must maintain a diverse generation portfolio that does not rely too heavily on any single technology, such as short-duration storage, to meet its capacity needs. Notably, energy storage resources do not generate energy and must be charged either from the grid or another resource.

Thus, at times, energy storage resources act as additional load to the Company's system. When dispatched, currently economical energy storage is limited to two or four hours of full discharge output. To serve customer load, the Company needs dispatchable resources that are not inherently limited by the specified discharge duration of the resource or a need to charge. While energy storage resources do have high levels of capacity equivalence because they can help to serve load during peak loads, they have limitations and need to be supported by other resources. These characteristics are reflected in the Company's Resource Mix Study, which selects not only BESS and solar but also CTs and CCs as economically optimal additions to meet system capacity needs. Specifically, CTs are selected beginning as early as the winter of 2026/2027.

Q. WHAT OTHER BENEFITS DO THE PROPOSED CT RESOURCES BRING TO THE 2023 IRP UPDATE?

A. CTs can be constructed in the short time frame needed to develop new generation that can help address the Company's capacity needs identified in the 2023 IRP Update. The Company-owned CTs would also contribute to the significant amount

of capacity required to maintain at least 70% utility ownership of resources serving Georgia Power's customers, consistent with Commission policy.

Q. WHAT STEPS HAS THE COMPANY TAKEN TO SUPPORT THE DEVELOPMENT OF THE PROPOSED CT UNITS?

A. The Company entered an Agreement for Preliminary Engineering and Development Services and Option to Purchase Equipment that allows it to engage a joint and several consortium consisting of an Engineering, Procurement and Construction ("EPC") vendor and an Original Equipment Manufacturer ("OEM") in connection with the development of the CT units proposed at Plant Yates. The agreement provides a framework through which, the Company can negotiate an EPC contract under which the consortium will provide the necessary engineering, procurement, and construction services for the development of the CT units. To support the timely development of these units, the company has advanced a reservation fee to the consortium to provide for the procurement of long lead time equipment and required services. These steps help ensure the proposed CT units can be developed in the timeframe needed to support the Company's capacity needs identified in the 2023 IRP Update.

Q. IF THE COMMISSION DENIES THE COMPANY'S REQUEST TO CONSTRUCT THE CT RESOURCES AT PLANT YATES, WHAT DOES THE COMPANY REQUEST REGARDING COSTS SPENT TO DATE?

A. If this request is denied by the Commission, the Company requests any development costs not useful or transferable to other projects be deferred to a regulatory asset with the amortization period of the recovery to be determined in the next base rate case.

E. Potential Acquisition of Additional Ownership Interest in an Existing Asset

Q. IS THE COMPANY STILL EXPLORING THE POTENTIAL OPTION TO ACQUIRE AN ADDITIONAL OWNERSHIP INTEREST IN AN EXISTING GENERATING ASSET WITHIN THE SOUTHERN COMPANY FOOTPRINT TO ADDRESS THE FORECASTED NEEDS IN THIS IRP UPDATE?

A. No. Georgia Power was negotiating a potential option to acquire an additional ownership interest in an existing asset within the Southern Company footprint. However, the Parties were unable to reach an agreement at this time. The Company will continue to explore other potential resource solutions and opportunities to meet its projected capacity needs and will return to the Commission if additional resource options become viable.

V. DER AND DEMAND RESPONSE SOLUTIONS

Q. WHAT NEW DISTRIBUTED ENERGY RESOURCE AND DEMAND RESPONSE PROGRAMS ARE THE COMPANY REQUESTING IN THE 2023 IRP UPDATE?

A. The Company is proposing to increase its DER and demand response offerings to customers and leverage the benefits of these resources for all customers. The Company's proposal includes: (1) two new customer-sited DER programs, known as the DER Colocation and the DER Customer Owned programs; (2) a new Curtailable Load program for commercial and industrial customers; and (3) an expansion of the Residential Thermostat Demand Response DSM Program. These programs will more fully leverage resources that customers are seeking and support system reliability for the benefit of all customers.

A. DER Programs

Q. PLEASE DESCRIBE THE DER COLOCATION PROGRAM.

A. The DER Colocation program, as implemented through tariff DCL-1, will be an optional program available to qualifying commercial and industrial customers. Through tariff DCL-1, Georgia Power will own, operate, maintain, and control dispatchable DER 10 MW and above at customer premises, and dispatch the resources to provide system benefits to all customers. The DER will be connected to the electric system, thus allowing the Company to transmit the energy they produce to the system. During a local electric service outage, the supply-side DER will continue to provide participating customers with electric energy, enabling more resilient operations. At no time will the DER generation impact the participating customer's retail billed electric service while participating in DCL-1. In exchange for the enhanced resiliency service they receive, participating customers will make payments such that the resulting rate base value of the DER is below the system value realized over its asset life, thus benefiting all customers. Customers participating under the DCL-1 tariff will also be required to enter a program agreement with Georgia Power that will further establish the terms and conditions of participation.

Q. WHAT ARE THE BENEFITS OF THE DER COLOCATION PROGRAM?

A. The DER Colocation Program allows for all stakeholders to benefit. Participating customers receive enhanced resiliency service at a cost below the full price of an on-site asset. Non-participating customers benefit from system capacity resources that are procured below the value received by these customers. The program leverages DER to strengthen grid reliability for all customers, creates a more flexible and diverse resource mix, promotes cleaner DER resources, and increases resilience for participating customers.

Q. HOW WILL THE PARTICIPATING CUSTOMER PAYMENT BE CALCULATED?

A. The participating customer's payment will be calculated as the total cost of the asset less 75% of the net present system value over the life of the asset. This structure (1) ensures all customers will see a benefit based on the discounted system value credited, (2) mitigates the bad debt risk to non-participants, and (3) ensures that participating customers receive resilience benefits.

Q. PLEASE DESCRIBE THE DER CUSTOMER OWNED PROGRAM.

A. The DER Customer Owned Program, as implemented through the DCO-1 tariff, will be an optional program available to qualifying commercial and industrial customers and will operate much like the DER Colocation program, but with a few key differences. Through DCO-1, Georgia Power will operate and control customer-owned, new dispatchable DER 1 MW or greater, but less than 10 MW, located at customer premises and economically dispatch the resources to provide energy and capacity benefits to all customers. Customers may aggregate assets at multiple accounts to meet the 1 MW minimum requirement, provided that each account's DER is 250 kW or greater. Like with DCL-1, interconnection of the DER with the Company's electric system will allow the energy produced by the DCO-1 DER to be transmitted to the electric grid. During times of electric service outage or need, the supply-side DER will continue to provide participating customers with electric energy, enabling more resilient operations. At no time will the DER generation impact the participating customer's billed retail electric service while participating in DCO-1. Under this program, Georgia Power will provide participating customers with a credit on their electric bills in exchange for the Company's use of the customer's DER for dispatch. The DCO-1 credit will be based on the system value of the participating customer's DER over the period during which they subscribe to the DCO-1 program. As a condition of participation,

participating customers will be required to enter into a program agreement with Georgia Power that will further establish the terms and conditions of participation.

Q. WHAT WILL BE THE TERM LENGTH OF THE DER CUSTOMER OWNED PROGRAM CONTRACTS?

A. The DER Customer Owned Program will allow for contracts through 2031. At that time, the Company will evaluate the ongoing benefits that these resources may continue to provide to the system and all customers. This contractual arrangement will provide great benefits to non-participants, providing firm capacity in the short-term, without committing to longer-term agreements. Participating customers will receive guaranteed benefits and payments through 2031 with future payments and the associated system value for their customer-owned DER being assessed at that time.

Q. HOW WILL THE COMPANY CALCULATE THE CREDIT PAID TO PARTICIPATING CUSTOMERS IN THE DCO-1 PROGRAM?

A. A levelized credit payment equal to 75% of the system value of the DER asset will be paid over the contract period. This structure ensures that all customers will see a benefit based on the discounted system value credited, and that participating customers receive a fixed payment stream through 2031 on their DER asset, offsetting their investment costs.

Q. WHAT ARE THE BENEFITS OF THE DER CUSTOMER OWNED PROGRAM?

A. The DER Customer Owned Program allows for all customers to benefit. Participating customers receive a firm credit payment over several years, offsetting the cost of their DER investment. Non-participating customers benefit from capacity resources being procured below the system value. The program leverages DER to strengthen grid reliability for all customers, creates a more flexible and

diverse resource mix, promotes cleaner DER resources, and increases resilience for Georgia Power's participating customers.

Q. WHAT TYPE OF ASSETS WILL BE ABLE TO PARTICIPATE IN THE DER COLOCATION AND DER CUSTOMER OWNED PROGRAMS?

A. DER technology that may be utilized under DCL-1 includes, but is not limited to combustion turbines, reciprocating internal combustion engines ("RICE"), and other dispatchable technologies with firm fuel supply. The Company will limit eligible DER to dispatchable assets that are certified and permitted for non-emergency use by the Georgia Environmental Protection Division of the Department of Natural Resources. All participating DER assets will be subject to the requirements of interconnection studies.

Q. HOW MUCH GENERATION CAPACITY WILL BE RELIED ON THROUGH THE DER COLOCATION AND DER CUSTOMER OWNED PROGRAMS?

A. The DER utilized in these programs will be peaking type resources and as such they should not exceed the unfilled peaking capacity needs in the system resource plan. These customer-sited DER programs allow the Company to meet its peaking resource needs by leveraging the same resources participating customers are seeking for their resiliency needs. In meeting this dual purpose, the programs can achieve greater overall economic efficiency.

Q. HOW WILL THE DER COLOCATION AND DER CUSTOMER OWNED PROGRAMS BE UTILIZED?

A. The DER in these programs will be dispatched for system use for both economic and reliability purposes, maximizing their value to all customers. Assets will also operate in the event of a local outage to provide resiliency to the customer.

Q. HOW WILL DER IN THE DER COLOCATION AND DER CUSTOMER OWNED PROGRAMS BE APPROVED?

A. In this IRP Update filing, the Company is seeking approval of the proposed programs, and the authority to begin developing projects with participating customers. The Company plans to submit the proposed DCL-1 and DCO-1 tariffs, along with the CL-1 tariff, for Commission approval prior to the direct hearings of Georgia Power. Once DCL-1 and DCO-1 projects are fully developed and contracts are executed, they will then be filed for certification and approval with the Commission.

Q. ARE THE DER COLOCATION AND DER CUSTOMER OWNED PROGRAMS APPROPRIATE FOR INCLUSION IN THE 2023 IRP UPDATE?

A. Yes. The enrollment of participating customers coupled with the development and construction of DERs require substantial lead time before the DERs become operational. Approving the DER Colocation and DER Customer Owned programs now expedites the realization of capacity benefits that these resources can provide to all customers. Any delay in approving these programs produces a delay in any potential capacity benefits to all customers.

B. Curtailable Load Program

Q. PLEASE DESCRIBE THE COMPANY'S PROPOSED CURTAILABLE LOAD PROGRAM.

A. The Curtailable Load program will enable additional demand response participation options to commercial and industrial customers and provide corresponding system capacity and reliability benefits to all customers. This optional DCL-1 tariff, through which the program will be implemented, will be available to qualifying commercial and industrial customers able to make multi-

year commitments to reduce their load during extreme supply and demand conditions.

Q. WHAT ARE THE BENEFITS OF THE PROGRAM?

A. The curtailable load program provides significant benefits to both participating customers and the system by reducing consumption during extreme conditions for grid reliability. Participating customers receive lower electric bills and non-participating customers receive the savings of deferred generation capacity infrastructure. The program leverages load flexibility to strengthen grid reliability for all customers, creates a more flexible resource mix, and provides economic benefits for participating customers.

Q. HOW DOES THE CURTAILABLE LOAD PROGRAM DIFFER FROM THE COMPANY'S EXISTING DEMAND RESPONSE PLUS ENERGY CREDIT ("DPEC") DEMAND RESPONSE PROGRAM?

A. This program will differ from the Company's existing DPEC demand response program in several ways. First, it will require multi-year contracts, which provide increased system value and assurance, and resulting increased credit values for participating customers. Second, the Curtailable Load program will reflect a value for capacity in both the winter and summer periods. Third, the curtailable load program will require demonstration on a regular basis to ensure demand response availability. Finally, the program will also have an updated compliance incentive to provide ongoing inducement to participate.

Q. WHY IS THE CURTAILABLE LOAD PROGRAM APPROPRIATE FOR INCLUSION IN THE 2023 IRP UPDATE?

A. Demand side options have long been a source of capacity for the system reflected in the resource plan. The Curtailable Load program can provide a more reliable source of new carbon-free capacity in an environment where firm capacity assets

are becoming scarce. Additionally, since demand response does not necessarily require any construction, realization of benefits can materialize more quickly and defer the procurement of future, additional capacity.

C. Expansion of Residential Thermostat Demand Response DSM Program

Q. PLEASE DESCRIBE THE COMPANY'S RESIDENTIAL THERMOSTAT PROGRAM.

A. Georgia Power's Temp Check is a residential thermostat demand response ("TSTAT DR" or "Temp Check") DSM program that allows the Company to make event calls that adjust participating customers' thermostat behavior during a limited period. The Company pays participating customers an incentive for this ability.

Q. WHAT CHANGES IS THE COMPANY PROPOSING TO MAKE IN THE TSTAT DR PROGRAM?

A. The Company proposes expanding customer enrollment in the Temp Check program to 50,000 customers.

Q. WHY IS EXPANDING THE TSTAT DR PROGRAM APPROPRIATE FOR INCLUSION IN THE 2023 IRP UPDATE?

A. The Temp Check program is a source of demand response potential that translates to capacity value. The program has seen robust customer participation and is currently closed to new enrollment. In addition, the program now reflects positive Total Resource Cost ("TRC") results for the evaluation life of the program and, therefore, no longer requires a waiver of the TRC requirement within Commission Rule 515-3-4-.04(4)(a)(3) as was approved in the 2022 IRP.

Q. DOES THE COMPANY BELIEVE THAT ADDITIONAL POTENTIAL EXISTS BEYOND THE REQUESTED 50,000 TSTAT PARTICIPANTS?

A. Yes, the Company believes that further residential load flexibility potential exists. The Company believes doubling the existing TSTAT DR program over the remainder of the DSM cycle reflects an aggressive but achievable expansion of the program. The Company will continue to evaluate and expand load flexibility programs where those options can deliver cost-effective value to all customers.

VI. CUSTOMER IMPACTS

Q. WHAT COSTS ARE ASSOCIATED WITH THE COMPANY'S PLAN PROPOSED IN THIS 2023 IRP UPDATE?

A. Georgia Power is committed to maintaining affordable rates for all customers and to ensuring that the costs of electricity are appropriately allocated among customers. Regarding the capacity resources requested in the 2023 IRP Update, Georgia Power will continue to adhere to its long-standing requirement that new economic development projects have long-term projected net benefits to Georgia Power customers. Accordingly, each new economic development project has to pass financial and economic screening requirements, including the Ratepayer Impact Measure ("RIM") test. Georgia Power expects existing and new customers to recognize economic benefits from this energy usage growth, which will help offset and balance the cost of investments needed to serve Georgia's growing energy needs.

Q. IS THE COMPANY REQUESTING A RATE INCREASE AS PART OF THE 2023 IRP UPDATE?

A. No. Consistent with the Company's prior IRP filings, Georgia Power is not requesting a rate adjustment in the 2023 IRP Update.

Q. WILL CUSTOMER BILLS EVENTUALLY INCREASE BECAUSE OF THE REQUESTS INCLUDED IN THE 2023 IRP UPDATE?

A. All else being equal, considering the expected load growth and cost of the solutions proposed in this 2023 IRP update, the Company does not expect customer rates to increase. The recovery of costs associated with new facilities that serve customers will continue to be addressed through the rate case process, where the Commission will establish reasonable rates based upon the Company's overall cost to serve. As noted above, each economic development project must pass financial and economic screening requirements, including the RIM test.

VII. FLEX CAPACITY

Q. IF THE COMMISSION APPROVES THE REQUESTS IN THE 2023 IRP UPDATE, WILL THE STATE'S ENERGY NEEDS BE MET UNTIL THE 2025 IRP?

A. If approved, the requests in the 2023 IRP Update should allow Georgia Power to meet the needs of its customers and the state based on current projections. Given the extraordinary economic growth in Georgia, the Company is closely monitoring the energy needs of customers and will work with the Commission to address future changes should they be necessary. To that end, the 2023 IRP Update establishes a framework within which the Company can request approval to acquire additional capacity ("Flex Capacity") ahead of the 2025 IRP if an updated load forecast projects additional capacity needs.

Q. PLEASE DESCRIBE THE COMPANY'S PROPOSED FLEX CAPACITY FRAMEWORK.

A. The Flex Capacity framework would authorize Georgia Power to undertake and recover the cost for preliminary development activities in connection with the development, operation, and ownership of new capacity resources. Additionally,

the Company would be authorized to continue to explore PPA or acquisition options that could be presented for Commission approval and certification prior to the filing of the Company's 2025 IRP and recover any incremental cost incurred for this effort. Georgia Power proposes that the following criteria must be met before the Company could pursue such options: (1) an update to the 2023 IRP Update load forecast that results in a 500 MW or greater capacity need prior to the winter of 2028/2029; and (2) the Company submits the proposed resource(s) for certification with an updated capacity needs chart and associated load forecast update.

Q. WHAT IS THE PURPOSE OF THE COMPANY'S PROPOSED FLEX CAPACITY FRAMEWORK?

A. The Flex Capacity framework allows for continued resource development flexibility in the coming years. Georgia Power plans to continue to identify supplemental or "Flex Capacity" resource options that could help meet additional capacity needs prior to the winter of 2028/2029, if necessary. For example, Georgia Power may identify BESS capacity opportunities in addition to the 1,000 MW proposed in this 2023 IRP Update. Additionally, the Company could continue to explore the possibility of additional PPA options associated with limited market resources, although none were identified by the Company's RFI issued in September and filed in the Company's Supplemental Filing on December 4, 2023, in this proceeding. If approved by the Commission, the Flex Capacity framework would help Georgia Power address rapid increases in load prior to the Company filing its 2025 IRP and continue to support economic growth in Georgia.

Q. WHAT REGULATORY AND RATEMAKING TREATMENT IS THE COMPANY SEEKING FOR ITS FLEX CAPACITY FRAMEWORK?

A. Under this proposal, the Company would be approved to defer any developmental costs for such activities that would otherwise be expensed into a regulatory asset, with the amortization period to be determined in the Company's next base rate case.

Once resources are identified under this framework, the Company will seek expedited certification for such resources.

VIII. TRANSMISSION

Q. PLEASE DESCRIBE THE SCREENING ANALYSES THE COMPANY USED TO EVALUATE THE TRANSMISSION IMPACTS OF THE RESOURCE SOLUTIONS INCLUDED IN THE 2023 IRP UPDATE.

Georgia Power performed transmission screens for various generation resource options considered by the Company to support its generation resource needs as described in the 2023 IRP Update. The screens utilized transmission power flow analyses across various scenarios of incremental resource additions. Each scenario included all the large load projects that have selected Georgia Power as well as prior queued projects. The screens provided estimated costs for transmission improvements that are attributable to resources proposed in this 2023 IRP Update, and they identified temporary capacity limitations until certain transmission improvements are completed.

Q. PLEASE EXPLAIN THE COMPANY'S REQUEST RELATED TO TRANSMISSION.

A. In the 2023 IRP Update filing, the Company requested approval of "expansion of the transmission system to accommodate the above-requested resources and the Company's Load and Energy Forecast as described in the Technical Appendix." Following discussions with Commission Staff, the Company seeks to clarify this request. Specifically, the Company requests approval of the transmission improvements necessary to accommodate the resources proposed in the 2023 IRP Update. Such improvements were identified in the preliminary transmission screening analyses filed in the Technical Appendix to the 2023 IRP Update and are consistent with the types of transmission improvements typically required to accommodate new generation added to the System.

Q. HAS THE COMPANY PROVIDED ANY ADDITIONAL SUPPORT OR ANALYSIS SUPPORTING THE TRANSMISSION REQUEST?

A. The Company is currently conducting additional, more detailed transmission studies on the transmission impacts of the 2023 IRP Update. The Company will submit a 2023 IRP Update Supplemental Filing in January 2024 that will include this additional analysis and support. Importantly, the supplemental transmission studies will incorporate potential new large loads consistent with the 2023 IRP Update Load and Energy Forecast in addition to the committed loads included in the preliminary transmission screening analyses described above. The Company does not anticipate the results from the supplemental transmission studies to materially deviate from the results of the screening analyses.

Q. WHY IS TRANSMISSION CRITICAL FOR AN EFFECTIVE AND RELIABLE FLEET?

A. The Company's generation fleet does not operate in a vacuum and cannot reliably serve customers without a reliable transmission system. Georgia Power must consider how resource planning decisions impact the transmission system, especially considering the planned fleet transition and retirement of the Company's coal resources. The Company identified transmission constraints relevant to fleet transition both in the ten-year plan and other unit retirement scenarios that were evaluated.

Q. ARE THERE TRANSMISSION IMPACTS AND RELATED COSTS ASSOCIATED WITH THE ADDITION OF THE NEW LARGE LOAD PROJECTS?

A. Yes. The Company studies and evaluates the transmission infrastructure necessary to accommodate the additional large load projects as they are proposed to be added to the System. The costs for such transmission impacts will be direct assigned, local, or upstream from the project.

Q. HOW ARE TRANSMISSION COST ASSOCIATED WITH NEW LARGE LOAD PROJECTS RECOVERED?

A. Direct assigned and local costs will be paid for by the customer either directly, through upfront payments, or through their rate offering and resulting revenue. Any upstream transmission costs caused by the addition of the new large load customer are built into the customer's rate and will be paid for by the new customer over time for the life of the project. Prior to making an offer to serve a customer choice opportunity, the Company analyzes the cost to serve the customer including the necessary transmission upgrades and investments needed to accommodate the load addition. The Company only extends competitive offers to eligible customers that pass financial and economic screening requirements, including the RIM test.

IX. CONCLUSION

Q. WHAT IS GEORGIA POWER REQUESTING OF THE COMMISSION IN THE 2023 IRP UPDATE?

A. The Company seeks approval of its 2023 IRP Update as proposed, including the following:

1. Authorization to procure the resources described in items 2-6 and 9 below in accordance with Commission Rules through the exceptions to the Commission's RFP process set forth in Commission Rules 515-3-4-.04(3)(f)(3), 515-3-4-.04(3)(f)(6), and 515-3-4-.04(3)(f)(7).

2. A certificate of public convenience and necessity for the PPA Between Georgia Power Company and Mississippi Power Company as described in Attachment A and the Technical Appendix.

    a. Regulatory asset treatment to defer the capacity and non-fuel energy payments made under the PPA, including additional sum, net of the wholesale capacity and non-fuel revenues from any remarketed capacity sales from January 1, 2024, through December 31, 2025, including an executed system sale to a regional electrical service provider during that time, for recovery in the next base rate case.

3. A certificate of public convenience and necessity for the PPA Between Georgia Power Company and Santa Rosa Energy Center LLC as described in Attachment B and the Technical Appendix.

    a. Regulatory asset treatment to defer the capacity and non-fuel energy payments made under the PPA, including additional sum, net of any wholesale capacity and non-fuel revenues from any remarketed capacity sales from January 1, 2024, through December 31, 2025, for recovery in the next base rate case.

4. Authority to develop, own, and operate up to 1,000 MW of BESS at various sites as described in this IRP Update and the Technical Appendix.

    a. Approval that any development costs not useful or transferable to other projects be deferred to a regulatory asset for recovery in the next base rate case in the event this request is denied.

5. Authority to develop, own, and operate up to 1,400 MW from three simple cycle CT resources at Plant Yates as described in this IRP Update and the Technical Appendix.

    a. Approval that any development costs not useful or transferable to other projects be deferred to a regulatory asset for recovery in the next base rate case in the event this request is denied.

6. Approval of two new customer-sited DER programs as described in this IRP Update.

7. Approval of one new tariff-based demand response program as described in this IRP Update.

8. Approval of an amended certificate for one existing demand response DSM program as described in this IRP Update and Attachment C.

9. Approval of the Flex Capacity framework as described in the Flex Capacity section.

    a. Regulatory asset treatment to defer any developmental costs for such activities that would otherwise be expensed for recovery in the next base rate case.

10. Transmission system improvements to accommodate the above-requested resources needed in support of the Company's Load and Energy Forecast as described in the Technical Appendix.

Q. DO THE REQUESTS IN THE 2023 IRP UPDATE RELIABLY MEET CUSTOMERS' GROWING ENERGY NEEDS AND PROVIDE ECONOMIC BENEFITS TO EXISTING AND NEW CUSTOMERS?

A. Yes. The balanced portfolio of resources proposed in the 2023 IRP Update provides reliable power to meet Georgia Power's capacity needs starting in the winter of 2025/2026 and provides a foundation for the Company's long-term capacity needs and the continued transition of its generation fleet to cleaner resources. The Company expects that the projected revenues associated with incremental customer load will offset the costs of the resources requested in this filing and put downward pressure on overall retail rates as Georgia Power continues to provide clean, safe, reliable, and affordable power for its 2.7 million customers.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

CERTIFICATE OF SERVICE

I hereby certify that I have this day served a copy of the within and foregoing DIRECT TESTIMONY OF THE PANEL OF JEFFREY R. GRUBB, FRANCISCO VALLE, LEE EVANS, AND MICHAEL A. BUSH ON BEHALF OF GEORGIA POWER COMPANY IN DOCKET NO. 55378 upon all parties listed below via electronic service or by hand delivery and addressed as follows:

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This 4th day of December 2023.



Allison W. Pryor
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BY MR. HEWITSON:

Q Mr. Grubb, also on December 4th, did you file or cause to be prefiled a supplemental filing to the 2023 IRP Update?

A (Witness Grubb) I did.

MR. HEWITSON: And, Chairman Shaw, for the record, I would like to identify Georgia Power Company's supplemental filing to the 2023 IRP Update as Exhibit GPC 3 for the trade secret version and GPC 4 for the public disclosure version.

CHAIRMAN SHAW: So marked.

(The documents referred to were marked for identification as GPC's Exhibits 3 and 4.)

BY MR. HEWITSON:

Q On December 7, 2023, did you file or cause to be filed an errata to the supplemental filing?

A (Witness Grubb) I did.

MR. HEWITSON: And, for the record, Chairman Shaw, I would like to identify Georgia Power Company's errata to the supplemental filing as GPC 5 for the trade secret version and GPC 6 for the public disclosure version.

(The documents referred to were marked for identification as GPC's Exhibits 5 and 6.)

CHAIRMAN SHAW: So marked.

MR. HEWITSON: Okay.

BY MR. HEWITSON:

Q Mr. Grubb, on January 10th, 2024, did you file or cause to be filed an errata to the 2023 IRP Update filing and direct testimony?

A (Witness Grubb) I did.

MR. HEWITSON: Chairman Shaw, for the record, I would like to identify Georgia Power Company's errata to the 2023 IRP Update as Exhibit GPC 7.

CHAIRMAN SHAW: So marked.

(The document referred to was marked for identification as GPC's Exhibit 7.)

MR. HEWITSON: Okay.

BY MR. HEWITSON:

Q And, Mr. Grubb, on January 12th, 2024, did you file or cause to be prefiled an updated economic analysis supporting the 2023 IRP Update?

A (Witness Grubb) I did.

MR. HEWITSON: And, Chairman Shaw, I would like to mark the updated economic analysis filed by Georgia Power on January 12th as GPC 8.

CHAIRMAN SHAW: So marked.

(The document referred to was marked for identification as GPC's Exhibit 8.)

MR. HEWITSON: With your permission, Chairman

Shaw, I would like for Mr. Grubb to summarize the prefiled testimony of this panel.

CHAIRMAN SHAW: Mr. Grubb, go ahead.

MR. GRUBB: Good morning, Commissioners. We appreciate the opportunity to be here with you today in support of Georgia Power Company's 2023 IRP Update. In the last 18 months, we have seen tremendous economic growth in Georgia, which is an exciting time for our state.

The 2023 IRP Update is a direct response to this extraordinary economic growth and requires Georgia Power to act now to procure and develop new supply-side and demand-side dispatchable capacity resources to meet the energy needs of our state, following the Commission's rules which contemplate such extraordinary events. As such, the IRP update identifies the effect of recent economic growth on the company's load forecast and capacity needs and proposes a well-balanced portfolio and resource plan that is expected to put downward pressure on rates for all customers and enable Georgia Power to continue to provide clean, safe, reliable and affordable energy for Georgia as it continues to grove and thrive.

The tremendous growth Georgia has been seen

since the 2022 IRP has brought more than 38,000 jobs and $24 billion in capital investment and is largely driven by Georgia's continued recognition as one of the best places in the country to do business, as well as strong customer growth across the company's residential, commercial, and industrial classes. Georgia's constructive regulatory environment, including the policies of this Commission, as well as significant infrastructure investments and the growth of emerging industries, contribute to this beneficial growth.

Georgia Power's 2023 IRP load forecast update -- or update load forecast projects continued unprecedented load growth stemming from the economic growth taking place in the state. Our updated projections far exceed those in the 2022 IRP, which were appropriately informed by historical information and foreseeable trends known at the time of that filing. The recent economic growth has far surpassed the historical trends upon which the company's forecasts have been traditionally based.

For context, the company initially anticipated less than 400 megawatts of growth between the winter of '23/'24 and the winter of 2030 and 2031. In contrast, because of the rapid pace of economic

development in Georgia, current projections show load growth of about 6,600 megawatts over that same time period. Nothing in the company or state's history could have anticipated growth of this magnitude. Importantly, similar growth is also being experienced by other utilities nationally as they face similar trends in increased electricity demand.

To be clear, the economic growth we are seeing benefits our state. As I'll discuss, it also benefits all Georgia Power customers by putting downward pressure on rates.

Notably, the baseline load forecast presented in this case uses the methodology that has been approved by the Commission in each of the company's IRPs -- prior IRPs. In addition, the company has incorporated external adjustments to the commercial and industrial classes in its forecast to account for the recent growth in the number of new, large-load projects the company has been selected to serve, as well as the considerable pipeline of potential future projects. While the use of external adjustments to its forecast is consistent with previous forecasts, the company developed a model to better capture the unique characteristics of these new, large-load customers and the relative probability of Georgia

Power being chosen to serve them.

To calculate this external adjustment, the company set out to answer two questions: First, will these new, large-load customers choose to locate or expand in the state of Georgia, and, two, will they select Georgia Power to be their electric service provider?

If the answer to those questions is yes, the company analyzed what the resulting load would be, when it would show up, and at what level. Starting with the full economic development pipeline, the company used proven mathematical techniques to assess the probability of each of these decision points. With this information, the company then considered a range of possible outcomes and appropriately incorporated an external adjustment to its baseline forecast to account for the portfolio of large-load customers to be served.

The increase in the projected demand of energy being driven by Georgia's economic growth has significantly impacted the timing and magnitude of the company's projected capacity needs. Based on the load levels projected in the 2023 IRP Update, the company now has a capacity need three years earlier than what was projected in the 2022 IRP. Therefore,

it must deploy new resources by the end of 2025 instead of by the end of 2028. To ensure it can meet the energy needs of the growing Georgia, and to continue to reliably serve its customers, the company plans to meet its winter capacity needs through the winter of 23 -- 2030 and 2031 with a combination of the resources requested in this IRP, which will address the accelerated capacity needs starting in the winter of '25/'26, and resources that will be selected in the All Source and the Energy Storage Systems RFPs that were approved in the 2022 IRP, which will address capacity needs starting in the winter of '28 and '29.

In this IRP update, Georgia proposes to procure and deploy the following supply-side capacity resources: First, purchase power agreements or PPAs to purchase capacity and energy from Mississippi Power Company for 750 megawatts, and from the Santa Rosa Energy Center for 230 megawatts.

Second, up to 1,000 megawatts of battery energy storage systems, or BESS, and/or BESS plus solar at various sites, including the Robins and Moody projects, and the 200 megawatt BESS plus solar project.

Third, up to 1,400 megawatts from three

combustion turbines, or CTs, at Plant Yates, as well as the transmission improvements necessary to support those units.

The company has asked the Commission for certification of the Mississippi Power PPA and the Santa Rosa PPA, which were executed prior to the filing of this case. As the company completes its negotiations with the Robins and Moody's BESS, as well as the Yates EPC agreement, and identifies additional BESS resources, the company will return to the Commission to request certification of those resources. Also, the company requests approval of the transmission improvements necessary to facilitate delivery from the Plants Yates CTs.

The company is also proposing to increase its distributed energy resources, or DER, and demand response customer offerings and to leverage the benefits of these resources for all customers. The company's proposal includes: Two new customer-sited DER programs, known as the DER colocation and the DER customer owned programs; a new curtailable load program for commercial and industrial customers; and the expansion of the residential thermostat demand response DSM program.

This portfolio of economic and reliable

capacity resources is designed to timely address the company's capacity needs and enable it to continue providing its customers with clean, safe, reliable, and affordable electric service.

Although there are costs associated with implementing the proposed resource plan, Georgia Power is not requesting a rate adjustment in this IRP update. In fact, all else being equal, the company does not expect customer rates to increase as a result of the company's requests in this case. In addition to proposing a cost-effective means of addressing the energy needs of our customers in this period of extraordinary economic growth, the company's plan in this IRP update is expected to provide economic benefits for all customers by placing downward pressure on rates. To help ensure the benefits to all customers, the company incorporates the cost to serve these new customers, including any necessary transmission upgrades, into the rate offers for each new large load customer. For each new economic development customer, their project must pass the rate impact measure or RIM test, ensuring that it places downward pressure on rates for all customers. Each new MW of load growth is an opportunity to place downward pressure on rates

as it provides for a larger customer base over which to spread costs necessary to serve all customers.

Commission approval of the company's resources in this case should allow Georgia Power to meet currently projected capacity needs. However, given the extraordinary economic growth in the state, the company proposes a framework whereby the company can request approval to acquire additional capacity ahead of the '25 IRP if certain criteria are met. In certain circumstances, Georgia Power would be able to commence preliminary development work towards acquiring new capacity resources or PPA options to meet increased customer demand beyond that identified in this 2023 IRP Update. This flexibility is a key component between now and the next IRP in 2025 to ensure that Georgia continues to be a top destination for economic development by allowing the company to adjust in more real time to the needs of our customers.

In conclusion, the state of Georgia has seen historic and tremendous economic growth, which requires additional capacity and energy and has contributed to the need for additional resources for Georgia Power's system and the need to act now. The '23 IRP Update presents a reasonable and balanced

portfolio of resources that meets Georgia Power's capacity needs beginning in the winter of '25/'26, provides a foundation for long-term capacity needs, and supports the continued transition to cleaner resources. The company expects that revenues associated with increased load will more than offset the cost of the requested resources and put downward pressure on rates -- on overall retail rates. Georgia Power remains committed to providing clean, safe, reliable, and affordable power for its 2.7 million customers and, accordingly, we ask the Commission to approve the company's 2023 IRP Update.

Thank you.

MR. HEWITSON: Chairman Shaw, before I make the witnesses available for questions and cross-examination, I've already screwed up my numbering.

The updated economic analysis that was filed on January 12th, there were two versions, a trade secret version, which I would like to mark as GPC 8 and the public disclosure version as GPC 9.

CHAIRMAN SHAW: So marked.

(The document referred to was marked for identification as GPC's Exhibit 9.)

MR. HEWITSON: Now the witnesses are available

for questions from the Commission, as well as cross-examination.

CHAIRMAN SHAW: Commissioner Echols.

VICE-CHAIRMAN ECHOLS: Hey, gentlemen, how are you doing?

MR. GRUBB: Good. How are you, sir?

VICE-CHAIRMAN ECHOLS: Good. I hear you saying that we need new resources, but how can we get more out of what we already have on the system, that we've already paid for or that customers have already installed?

How can we better utilize that?

MR. GRUBB: Well, Commissioner, I mean, that's in the plan; right?

So -- so adding the Vogtle units is incorporated into the plan. All of the IRP in 2022, all the RFPs that were approved in the 2022 IRP are going to help meet these needs, as well. It's just they can't meet them as early as we need them now. And so we are leveraging the entire system, but you -- the load growth is just making it such that we've got to add resources.

So when you think about coming out of the 2022 IRP, we actually had some length above our target reserve margin. We had the PPAs coming in a little

bit earlier than some of the coal retirements. That length is help serving part of this load. But it's that incremental load that we've got to add these resources for.

So we are leveraging things. Some of the things we're leveraging is solar. So Mr. Bush can speak to this. The Robins and Moody's projects are solar facilities that we're adding storage to that will allow those solar facilities to help on winter mornings, like this morning and tomorrow. And so we are leveraging them from that standpoint.

So we are, but there's -- there's still the need to add more.

VICE-CHAIRMAN ECHOLS: Yeah, I love that.

Let me ask you the same question that I asked the students about -- about the -- the residential solar. So I have solar on my house, a small array. I could have put more.

But if we had more people participating in our solar programs on the Georgia Power system and they installed larger systems, would -- and they were feeding back onto the grid on a daily basis, would that be helpful or hurtful to this situation?

MR. GRUBB: So for this situation it's not helpful because we're focused on those -- our

reliability is driven by those cold winter mornings. And so when we looked at resources to meet these new needs, rooftop solar doesn't help meet that need.

Now, that doesn't mean that rooftop solar doesn't help. I know we just went through a lot in the 2022 regulatory cycle on rooftop solar. And I expect we will again in the '25 regulatory cycle.

So it does help. It's more of a solar ben- -- a summer benefit than a winter. So that's why when we were looking at resources to meet the needs in this case, we didn't look at rooftop solar because it doesn't hit that winter morning peak that's our main concern of adding resources right now.

VICE-CHAIRMAN ECHOLS: So with more of these solar customers adding batteries to their array because they don't want to feed back onto the grid, are you familiar with these programs -- I think Duke is implementing one, Arizona is doing one -- where customers can purchase or lease a battery system and participate in a utility called demand response event?

Are you familiar with those?

MR. GRUBB: I'm relatively familiar with them. I don't deal with them every day. But I think that's one of the things that when we approach the '25 IRP

we'll continue to look at.

You know, we're always looking on that normal IRP cycle at programs that we can do on the distributed side. I know there's more things we've got to figure out on the DERMS, or the control system side, but I think that's something we're definitely still looking at, Commissioners -- Commissioner. We just didn't identify it in this case because it doesn't help meet this advanced winter need, mostly driven by winter need.

VICE-CHAIRMAN ECHOLS: So you do see a time in the future where the utility might get a look at the state of charge of that home battery and have access to it through the algorithm to be able to call it and compensate the customer?

MR. GRUBB: I think that's something that we were looking at. I mean, I know a lot of other utilities have, too.

I don't personally look at that every day, but I know there's folks looking at those programs and what things we might need to tee up and bring forth to the Commission in the '25 IRP.

VICE-CHAIRMAN ECHOLS: Do you see electric vehicle batteries representing the same type of demand response potential on a cold winter morning?

MR. GRUBB: There -- there's discussions around that. Again, for this case we didn't look at it because we need 3,000 megawatts of resources. And while those resources could help, I -- we don't think in the magnitude that we need for the timing of this case.

So I know those are things that the utility industry is looking at and some folks in our company are looking at it, just not me personally. But, again, for this case, it didn't help us solve the problem and this was focused on meeting the issue that we have here today.

VICE-CHAIRMAN ECHOLS: Okay. Thank you.

MR. GRUBB: Uh-huh.

CHAIRMAN SHAW: Commissioners, any other questions?

I've got a question, I guess for you, Mr. Grubb. I'll be honest, I'm still kind of scratching my head on how we -- how we ended up here, you know, when it seems with like we just finished the last IRP.

MR. GRUBB: I feel the same way, Commissioner.

CHAIRMAN SHAW: Yeah, I understand.

But, obviously, in your testimony and all of the data requests that we've looked at, you know,

there is a lot of information to justify what we're dealing with and why we're dealing with it.

But, I guess, of this generational growth, unprecedented growth in the load and in our economy, is there one singular thing that you would be able to point to possibly that you could attribute a lot of this load growth to?

MR. GRUBB: So I'll let others on the panel jump in. I mean, Mr. Chair, it really is an industry-changing, economy-changing type of move nationally. There's five or six other companies who are requesting IRP update for the same reasons we are.

So it's a -- it's a structural change that we haven't ever seen in an industry before. It's not just impacting Georgia. It's impacting other states, too.

So, I mean, I think it's part of moving clean industry manufacturing to the United States through some of the legislation. It's the growth in the need for data, in terms of streaming services and cloud services. That's a lot of the growth. But it's also just a move to more manufacturing and the scale of them.

So, again, others on the panel can chime in,

but it really is a transformational, generational-type issue. We've never -- and the charts in the filing show, we never had customers -- our entire largest annual customer choice win before the '22 IRP was 300 megawatts. Our largest customer is 100 megawatts.

So the fact that there's 17- to 20,000 megawatts of load that want to come to Georgia in the economic pipeline is mind boggling. And it developed late, late part of 2022 into '23. And so we were -- we were looking at those loads, we've spoken to that in the hearing, but it really is just a -- an astronomical change that everybody is seeing.

It's a great opportunity. And so when we started seeing the loads update, the capacity need is the main driver coming back to here. And so for the first several load forecast updates, that generation capacity renewal, that RFP in -- the '22 IRP for the winter of '29, that RFP has just gotten -- is getting bigger.

We had enough headroom coming out of the prior IRP to get us to '29 for several iterations of the load forecast. But once that load forecast moved that need year up was the driven -- the reason to ask.

So I don't know if Mr. Valle and Mr. Evans have anything, but it really is just a national economy move to a lot of these larger customers.

CHAIRMAN SHAW: I would just ask kind of a second part to the question, then you can weigh in.

So you mentioned the industrial growth and you mentioned the data. So you're referring to data centers; correct?

MR. GRUBB: Uh-huh, uh-huh.

CHAIRMAN SHAW: Okay. Would you say that the data centers and the growth in that sector is the primary driver of this increased load forecast?

MR. GRUBB: I think it's -- I think it's more than -- more than half. I think Mr. Valle has got more data there.

CHAIRMAN SHAW: Okay.

MR. GRUBB: I think it is. But I do think it's important to note, though, I mean, that's a -- that's growth that wants to go somewhere. It is -- it is not -- I mean, it's the way society is moving.

You think about streaming, you think about all the cloud based, you think about AI. I mean, so it is a national part of the economy that is growing. And it's an opportunity to add really good level load growth to help put down pressure on rates.

But as far as percentages, I think Mr. Valle has got more of the data on that.

MR. VALLE: Yeah. So thank you, Mr. Grubb.

So I think Mr. Grubb did a fantastic job at describing how we got here and the -- and the unprecedented nature, in terms of the pace and the size of the developments that we have seen.

So we have nothing -- we have nothing that we have seen in our history at a state level or at a company level that would have indicated that we would have been in this -- in this moment of time.

I think it's a -- it's a fantastic story. I think it's a success story for this Commission, for this state for being able to attract what has been recently a -- a national development.

So the manufacturing that is coming back to the state, the new manufacturing of electric cars, battery manufacturers, clean energy technologies, and data centers are phenomenons that are happening on a national scale. And because our state, it's among the top on the nation for doing business, we have been able to attract that activity.

The load -- the majority of the load, to answer the question, is coming from -- from data centers. I would say, subject to check, it's about 80 percent of

the total gigawatt hours. In terms of customers, it's a little bit lower. I would say 65 percent of them are -- are data centers.

But I would say the -- the portfolio of customers that we have to serve is what it constitute is a success story. Because although data centers tend to be larger than other customers, the -- the amount of attention and the amount of customers looking for service into our state have been nothing but a success.

MR. GRUBB: And, Mr. Chair, I want to add one thing. When we talk about data centers, we're -- it's -- there aren't many that are the crypto, high-risk-type data centers. These are data centers that are for streaming and AI and some of the -- the major players.

And so we'll talk more about how we put that into costing and how we handle all those types of things. But we're making sure that data centers are covering their cost, just like all other customers.

And I just wanted to point out that it's not the -- the higher-risk ones. If they are, we take that into account, but it's -- the majority of these are the -- they're data centers that are just part of that new move in the economy for all the data needs

that we have as a society.

CHAIRMAN SHAW: You mentioned some of the other industrial growth. Did -- has Georgia Power, did y'all -- were y'all selected to serve the Hyundai site?

MR. GRUBB: We were, yes, sir.

CHAIRMAN SHAW: And so I would assume if you're serving the -- the big plant, that you'll probably likely to pick up some of the suppliers in that same area?

MR. GRUBB: We are definitely going to compete for them, yeah. I hope that helps us, yes, sir.

CHAIRMAN SHAW: So I heard you say that the IRP update won't change rates, but could it cause revenue requirements to go up and higher rates being necessary in the -- in the 2025 rate case?

MR. GRUBB: So from the -- the request in this filing, we do not expect upward pressure on rates. We expect downward pressure on rates. And we say that based on the analysis that we did and then provided in the data request where we looked at exactly what you're asking.

So we looked at the revenue requirements for all the resources that we've requested in this IRP update compared to the revenues from the incremental

load that's driving the need for those resources. And that shows a -- a higher level of revenues than it does revenue requirements for these resources; thereby, putting downward pressure on all rates.

CHAIRMAN SHAW: And I'm assuming you'll -- you'll be able to provide more information as we go along on in the hearings?

MR. GRUBB: Yes, sir. I bet we get that opportunity.

CHAIRMAN SHAW: I hope so.

That's all the questions I have.

Any other questions, Commissioners?

COMMISSIONER PRIDEMORE: Go ahead.

COMMISSONER McDONALD: Is there any concern in that generation with the pressure that's being put on by the administration for the derailing of natural gas?

MR. GRUBB: I don't -- when you say derailing of natural gas, I'm not sure exactly what you're referring to, Commissioner, but --

COMMISSONER McDONALD: The lack of -- the lack of fracking, the lack of having the -- the energy coming to us with -- with what we are using now.

MR. GRUBB: Yeah. So we do -- we did factor some of those things into some of our expansion plans

that we've provided. That's something we've updated in that there's pressure on being able to add and build firm transportation for gas.

And so as we've done in every IRP, you know, we do those resource mix studies where we looked across all of our different scenarios and what might be the economic resources. We used to have more gas build than we do now because we felt like it was probably more than you could do. So we do reflect it there.

In terms of how we're engaged nationally, I can't speak to -- speak to that. But I think it's important to know on the -- this request, the Yates CTs, they are expected to run on natural gas the majority of the time. We're planning for that.

But we did not look at building the firm transportation to back those units up because we've got dual fuel with the oil backup because some of the timing challenges on getting that.

So I don't know exactly where the -- the administration is going to go with gas. Southern Company has said for a long time that gas has to play a role. And Georgia Power agrees.

When you look at the need for dispatchable generation, solar, storage, they're all very beneficial. We are moving towards them in a big way

and have moved towards solar in a big way, but a diverse portfolio is important. And -- and gas and dispatchable resources need to play a role in that.

COMMISSIONER PRIDEMORE: Mr. Grubb, you were just asked a question about the data centers and the types of data centers that are put into this -- into this filing. And you said there's, quote, not many high-risk crypto data centers.

How many high-risk crypto data centers are there?

MR. VALLE: We have two in the -- in the list. The portfolio of loads -- of large loads that is triggering the -- the reason is -- is the reason why we're here today has 51 projects. Two of them are -- are crypto.

COMMISSIONER PRIDEMORE: The two are high-risk crypto?

What's the total energy demand for those two?

MR. VALLE: I don't have it in front of me, but I would say it's -- it's significant.

COMMISSIONER PRIDEMORE: Are those two high -- those two high-risk users, are they under contract with Georgia Power currently?

MR. VALLE: I think so.

MR. EVANS: I'm not sure.

MR. VALLE: Subject to check, I'm not -- not sure.

COMMISSIONER PRIDEMORE: Could you check on those two items and get me answers for those, please?

MR. VALLE: Absolutely, yes.

COMMISSIONER PRIDEMORE: Thank you.

Mr. Evans, you recently talked about -- and I'll quote you -- in "Public Utilities Fortnightly." They'll be so excited that they're on the record here.

Page 44, you spoke about inserting demand response into the load calculations for the first time. This is the first time the company has done that.

Why?

MR. EVANS: Yes. That was a -- a longer quote that they took a -- a subset of. We've always reflected demand response on the resource selection. What I was speaking to on that panel was some enhanced methodology to more reflect the real value of demand response based on that shape; right?

But we've always shown demand response and demand-side dispatchable resources on the resource ledger and counted that capacity for all customers.

COMMISSIONER PRIDEMORE: Is that capacity

counted equally as capacity the company generates?

MR. EVANS: The capacity equivalence is. So there's a difference in the amount of capacity enrolled in the program, the amount we recognize on the resource ledger based on when that response can show up compared to when our resource needs might be throughout the year.

COMMISSIONER PRIDEMORE: The fact that for the first time this is being calculated in a more aggressive way than it has before, is that going to make the Georgia Power customer more likely to have a brownout or a blackout?

MR. EVANS: No. I think it firms up that resource. I think it more reflects the actual value and likelihood that it will be there when we need it. If anything, I think it strengthened the resource plan from -- from recognizing those resources.

MR. GRUBB: And, Commissioner, if -- my recollection on the number may be a little rusty from Winter Storm Elliott. But we had almost 500 megawatts on that cold winter morning in Winter Storm Elliott from our demand response programs.

COMMISSIONER PRIDEMORE: Will you check that number and get me an actual, please?

MR. GRUBB: I will.

COMMISSIONER PRIDEMORE: Thank you.

MR. EVANS: And to Mr. Grubb's point, coming out of Winter Storm Elliott is whenever we started evaluating and -- and we had already been looking at this, but implementing it and realizing what exactly during certain times of the year demand response likelihood is. Because demand response can only provide a value if that load is there; right?

And so if it can't be reduced during that cold winter morning or on Christmas Eve, then that's a -- that's a risk we have to take into account when recognizing that resource.

MR. GRUBB: And, Commissioner, I think I might have had the fastest response to a hearing request ever. I just couldn't remember if I had it.

So at 8:00 that morning, we were around 451 megawatts from Georgia Power and just over 980 for the system.

So to Mr. Evans' point, I -- I don't know what they meant by we've -- we never incorporated the math. We have always included that by demand response programs on our IRP to help meet that peak. So it did contribute to helping us.

COMMISSIONER PRIDEMORE: Okay. Was the -- and was that demand response primarily generated out of

your CNI customer base?

MR. GRUBB: I think actually --

COMMISSIONER PRIDEMORE: Or was it -- did it affect residential?

MR. GRUBB: No. Actually, the majority of it was our conservation voltage reduction, which is a power delivery program where we -- we change the voltage on the system for a few hours and save load that way. So I think it was about 50 percent that and the rest the others.

COMMISSIONER PRIDEMORE: CNI or residential?

MR. EVANS: Most of it's CNI.

MR. GRUBB: Most of it's CNI.

COMMISSIONER PRIDEMORE: Any residential?

MR. EVANS: A small amount.

COMMISSIONER PRIDEMORE: Were they warned ahead of time?

MR. EVANS: Yes.

COMMISSIONER PRIDEMORE: Were they given a choice?

MR. EVANS: There is an override capability for the residential demand response.

COMMISSIONER PRIDEMORE: How many customers affected; do we know?

MR. EVANS: I don't believe I have that right

now.

COMMISSIONER PRIDEMORE: Okay. If you could let me know, that would be good. Thank you.

MR. EVANS: Yes.

COMMISSIONER PRIDEMORE: The Hyundai announcement came to the state or was formally announced May of 2022. As we all know, the -- the Hyundai project, though, had been in the works for about a year prior to that.

The decision that the Commission gave to Georgia Power on the 2022 IRP, which is what this is an update to, came down in July of '22.

At any point in time did Georgia Power at that time consider adjusting their projections and calculations to be able to -- to address the Hyundai announcement?

MR. VALLE: Not at that point, Commissioner. So -- so the -- the actual win of -- of Hyundai happened by the end of 2022. So by the time that we developed the IRP, we knew --

COMMISSIONER PRIDEMORE: It happened May of 2022 and the -- May of 2022 was when it was formally announced --

MR. VALLE: Correct.

COMMISSIONER PRIDEMORE: -- and the deal was

signed.

MR. VALLE: Correct. So I --

COMMISSIONER PRIDEMORE: And then the Commission put down the decision for the 2022 IRP in July of 2022.

MR. VALLE: Uh-huh, yes. But -- but they didn't become our customers until after the IRP. Although we were mindful, the assumption at the time was that the baseline portion of the forecast was enough to capture the growth introduced by Hyundai. And -- and so it was determined at the time with the information that we had that we didn't have the need of having an external adjustment for Hyundai.

Later we did a -- a further analysis and -- and now we realize that the underlying baseline portion of the forecast was not enough and we considered them as external adjustment.

MR. GRUBB: And, Commissioner, we did have some customer choice wins at the -- that latter half of '22, after we completed the 2022 IRP. But, again, it wasn't enough -- the load forecast did go up by 12-, 1,300 megawatts, but it still wasn't enough to move that capacity need year up.

And then --

COMMISSIONER PRIDEMORE: Georgia Power didn't

feel it necessary to -- to alert the Commission in a formal way about the -- about the Hyundai announcement and the need to generate more electricity, knowing the impact that it would have?

MR. GRUBB: So I'm not sure what the company's position is on announcing to the Commission each project, but from a -- from a planning standpoint, it was not driving us to need to change our resource plan at that time. Not Hyundai alone, plus what we had seen.

So I can't speak to the other communication. But from a planning standpoint, while it was a load increase, it was not changing anything that we needed to do coming out of the 2022 IRP.

COMMISSIONER PRIDEMORE: So the -- the Hyundai project and the later 2022 wins that you just mentioned, Mr. Grubb, those were not enough for Georgia Power to issue this update earlier than 2024?

MR. GRUBB: That is correct. So, actually, when we look at this plan, everything that we've won is not the drive for this plan. This plan is for everything we've won, plus the potential to continue to support the growth of the state.

So those projects that once we won were not the driver for the update. This update is for the

combination of what we've won, plus to be able to continue to grow with the state. Just like any load forecast is, potential growth in the state. So none of the wins that we've done are driving this specific resource update.

COMMISSIONER PRIDEMORE: So if you can take the total amount of megawatts requested for this Commission to approve and you can group it two -- put it in two categories, megawatts or -- or capacity that's already been acquired, approved, contracted, licensed, whatever it called for, claimed, in one column, and future projection, we don't know if it's going to happen or not in the other, what's the split between the two?

MR. GRUBB: Do you know that?

MR. VALLE: So, yeah, I can -- I can address that, Commissioner. So the way that we have looked at that is -- it's in a probabilistic way.

So the -- the sources of -- of load that are considered large loads for the external adjustment, so -- let me make a pause to -- to make sure that you understand that the -- that the forecasting in itself hasn't changed. So the forecast is done with the same foundational blocks that have been guiding this -- this Commission and our planning system and

approved before, which means a short-term forecast, a long-term forecast, which what -- is what we call the baseline portion of the forecast. And then we use external adjustments; right? So we use external adjustments for EVs, behind-the-meter solar.

What is different now is that since the budget 2023, because of these large loads coming to our state, we needed to add another external adjustment, and we call that the external adjustment of large -- large loads.

Only -- only after 2023 was -- was finished have the amount -- the pace and speed of what these projects started to show accelerated. And -- and it was only in -- during the year 2023 is when we saw this -- this explosion of projects coming to our -- to our state.

Does that answer your -- your question?

COMMISSIONER PRIDEMORE: No, Mr. Valle. Sorry. It doesn't.

MR. VALLE: Can you --

COMMISSIONER PRIDEMORE: There's two columns. There's -- there's projects, there's megawatts, there's capacity, there's what is claimed, what's called for, what's licensed, what's contracted. We can call it whatever we want to call it, but what is

committed to, and then there is what is projected.

MR. VALLE: Okay.

COMMISSIONER PRIDEMORE: Which is not a customer, might be a customer one day, could be tomorrow, could be next month. Those are two different things.

I want the total loads of each type of customer.

MR. VALLE: Yes. So -- so it's not the way that -- that we forecast the load. And the reason is we have to project the load that we need to serve. So the planning process first identified the load that we need to serve and then solves for the infrastructure needed to remain reliable and -- and affordable for -- for our customers.

In the case of the portfolio, the external adjustment of -- of large customers, it's a portfolio approach. And we have assigned likelihoods to three sources of buckets. So there are customers that have selected the company already, there are customers that have selected the state but not our -- our company yet, and there are those that are selecting the state, but they haven't made a decision yet.

The combination of these three buckets, these three groups --

COMMISSIONER PRIDEMORE: Can I stop you right there, Mr. Valle?

MR. VALLE: Sure.

COMMISSIONER PRIDEMORE: You just said the same thing for numbers two and three, I believe, if I heard you right. It's customers that have -- that have selected the state but have not selected their electricity provider. That's -- that's classification two.

MR. VALLE: Yeah.

COMMISSIONER PRIDEMORE: And, again, we're working on the second column here. We're not working on -- on customers that are committed and that are today customers.

MR. VALLE: Right.

COMMISSIONER PRIDEMORE: We are working on the potential customers.

MR. VALLE: Yes.

COMMISSIONER PRIDEMORE: And it's those that have selected Georgia Power, which those should get moved into customer. There is those that have selected Georgia but have not selected their provider yet. That's the second option.

But the third option sounds exactly like the second option. What am I missing?

What is the difference?

MR. VALLE: The likelihood of becoming served by our customer. So our methodology basically, like -- like stated in the summation, it's -- it's designed to give you information about two main questions; right?

The first question is: Will each one of these customers become Georgia Power customers; right?

And some of those the answer is yes because we have won it.

And for some of the others, there is a likelihood that they may; right?

Then the -- the question becomes: If the -- if the answer is -- is yes, we can serve it, how much and when?

And -- and so of the customers that we have won, we have resources, but we have to analyze the potential; right?

We cannot ignore the load that wants to come to our state because that's not the way we plan the system. We have to plan for the system that our -- that -- the customers that are coming to our state looking to be -- to be serviced.

COMMISSIONER PRIDEMORE: Mr. Valle, I don't want to ignore that potential either.

MR. VALLE: Yeah.

COMMISSIONER PRIDEMORE: My question, though, is this: Of those that have selected Georgia but they have not selected their electricity provider yet, and they qualify for customer choice, how many of those people -- how many of those -- in terms of the megawatts of the capacity that is filed in this case, how many are represented by those people?

MR. GRUBB: So, Commissioner, what -- what we'll have to do, we'll have to go back and look into that. Because what Mr. Valle is saying is it's a -- it's a -- we run a hundred thousand different probabilities on that. And so within that load forecast, there's a probability of what the customers that we have gotten signed and selected us, what they're using.

It's not a customer A, B, C or D. So we'll have to do some work there. So it's -- it's just -- when you're having to look at all those different moving pieces, we don't have -- we don't have just a what we've been selected to serve forecast, then add the probability for the others that haven't selected it yet. There's some probability on those, as well, in terms of --

COMMISSIONER PRIDEMORE: Uh-huh.

MR. GRUBB: -- how fast it's going to stand up.

So we don't get a -- I don't believe we get a model that says: Each customer is this. It's just a total that captures all that.

So I think we'll have to dig into it, but we understand your question and we'll have to go back and figure out how we can pull those pieces out for you.

COMMISSIONER PRIDEMORE: So I'm looking for the detail on those customers that have selected -- that were not accounted for in the 2022 IRP.

MR. GRUBB: Right.

COMMISSIONER PRIDEMORE: They have selected Georgia. They have selected Georgia Power as their electricity provider.

MR. GRUBB: Right.

COMMISSIONER PRIDEMORE: Of those, what is their projected capacity or load, however you want to --

MR. GRUBB: Uh-huh.

COMMISSIONER PRIDEMORE: -- categorize it?

MR. GRUBB: We'll have to -- we'll have to -- we don't have that with us. We didn't split it out that way, but we'll have to --

MR. VALLE: So, Commissioner, I can -- I can

answer the question from an announcement perspective.

So -- so there is a -- there is a distinction that I want to make sure you understand. So one piece of information is the load announced by each customer; right?

COMMISSIONER PRIDEMORE: Uh-huh.

MR. VALLE: It's -- it's the sum of all the interconnected devices that they have behind the meter; right?

That is not the load that we have to serve. And for -- so for the interconnected load, I would say for the wins we have about 14 of the 51 that are currently customers that we have won. The other ones are all potential.

And then of the total --

COMMISSIONER PRIDEMORE: Say that again. You have 14 committed --

MR. VALLE: We have 14 committed --

COMMISSIONER PRIDEMORE: -- out of 52?

MR. VALLE: Out of 51.

COMMISSIONER PRIDEMORE: Fifty-one?

MR. VALLE: Yes.

Now, what is the load at the meter, that is a different answer. And that load is going to materialize at a lower level because there are some

diversity factors; right?

So when you ask for electric service, first you list all of the equipments that are behind the meter. Think about an industry that has motors, that has heaters, it has lighting; right?

When they operate, they don't use every single device at the same time. They use something lower. That diversity in the usage is what we need to consider it for for serving the load. And that number is coming as a portfolio and it's not something we can break down.

But the -- the load announcements definitely we can something -- something that we can provide in more detail to you.

COMMISSIONER PRIDEMORE: Load consideration is a part of the bid in customer choice. How much does load consideration change from once the bid is won?

MR. VALLE: I would say it's -- it doesn't. I'll -- I'll answer quickly and then I'll let Mr. Evans to complement.

But when -- when a customer comes for service in our state, they provide us with a ramp-up assumption, they provide us with a -- with a requirement of the -- of the load that they need to -- that -- that we need to serve over time; right?

That -- that amount doesn't -- doesn't change because it's part of the request for service. And our indication of cost, our pricing, is based on that -- on that curve.

Does that -- does that help?

COMMISSIONER PRIDEMORE: It doesn't answer the question, though.

MR. GRUBB: So, Commissioner, were you asking in the forecast?

COMMISSIONER PRIDEMORE: So customer usage, that is calculated and determined -- so we're -- we're talking about in the filing, the influx of CNI customers.

MR. GRUBB: Right.

COMMISSIONER PRIDEMORE: That is considered at the point when the customer decides Georgia Power to be their electricity provider; correct?

MR. GRUBB: That's right.

COMMISSIONER PRIDEMORE: That's right.

How much does their actual usage deviate from that projection that Georgia Power made to win that customer in the first place?

MR. VALLE: Okay. I can -- I can answer that question. So -- so there is a -- there is a range. I believe that the range is trade secret. But

it's -- it's a percentage below from that announcement.

Now, for -- what I can say is that for industrial customers, that percentage of load realization is lower than the percentage of load realization that you would expect from a data centers because data centers aim to maximize their energy use behind the meter.

Once they have their -- their computer, their servers, they run it. And the more they run it, the more powerful answer they can -- they can provide to us.

But it's -- it's in the form of a range. It's a -- it's a range that had been informed by the experience judgment of our professionals.

COMMISSIONER PRIDEMORE: I'd like to know the range.

MR. VALLE: Yes.

COMMISSIONER PRIDEMORE: But more importantly than the range, I want to know how many times Georgia Power is off-target of the range. So in the estimate that they've made in the choice bid, then if -- if they've -- if they've put forward the estimate, not just the -- of course, the price -- but the total load of the customer, how much are they off of that?

And, if so, is it more or is it less?

To your point, Mr. Valle, data centers, you should be able to nail it every time because they're going to tell you the number of servers, they're going to tell you the number of hours of operation, they're going to tell you what their -- what their install time is. You're going to know that.

But for a manufacturing customer, I can see why that -- there might be variance there. I want to know what the variance is and how often we're above it or below it, how often we nail it.

MR. VALLE: Yeah. So I can -- I can -- I can answer right now. The -- so the first part of the question, we can give you the ranges that we have assumed no problem.

In terms of the -- in terms of the verification of the load materialization, this has not been a business need. So it's not something that we currently have as information. It's something that we plan on tracking; right?

But, historically, once we won a customer -- choice customer, that customer becomes ours to -- to serve. But there wasn't a need to track the performance over time.

So if they say they -- they needed a certain

amount of energy and that's the interconnected load, we didn't track specifically. We have some anecdotal information. We have some -- some data that we could provide if -- if it's helpful.

The other piece is that, you know, we have to understand that the -- the new load is unprecedented, right, in terms of -- in terms of the size of the customers that -- that we have. And although we have experience servicing data centers and serving most of the industries that are coming to the state, the size in itself is unprecedented and without data.

So definitely something that we plan on -- on tracking. We -- with -- with any new development, we constantly examine the business practices that we do. This has not been a -- a need, but we definitely plan on -- on tracking it.

MR. EVANS: And, Commissioner, one thing about those -- about that load materializing or not materializing, right, that I think it's important in this conversation, talk about the structure of the RTP, the realtime pricing rate for Georgia Power.

Where as those offers are being made, there will be a percentage of that load -- based on that projection, that is billed at a otherwise applicable standard tariff; right? So not on realtime pricing.

Once that percentage is determined, whether that load materializes or not, the same amount of energy will be billed at that standard tariff; right? So if that load does not materialize, less load comes online, effectively that customer just has a higher average rate and a higher CBL percentage.

So if the load doesn't come online, that's essentially marginal load that doesn't come online, but the stand- -- the load that's billed at a standard tariff is the same.

COMMISSIONER PRIDEMORE: That makes sense.

I'm very concerned about customer rates related to this docket especially because what's being requested is a -- is a lot of increased infrastructure.

Mr. Grubb, you said that -- that rates are not likely to increase because of the result of this docket. Determine to me what "likely" means and how can we move your "likely" to a "will not increase"?

MR. GRUBB: So I would say based on this filing, they will not put upward pressure on rates. Mr. Evans can speak to the costing side on how we're doing.

We mentioned the rate impact measure test, but what we've done is what we've looked at and provided

in the DR was the revenue requirements for '26, '27, and '28 for these resources that are coming online to serve customers and the revenues. And we actually did the revenues at a lower load level than the resource plan. So we -- we have some -- a little bit of headroom in there.

So it's a -- a few hundred million dollars of downward pressure on rates from that analysis. And that's why we say we're -- from this filing, we -- we expect downward pressure for rates.

COMMISSIONER PRIDEMORE: Mr. Evans.

MR. GRUBB: I don't know how -- I'm sorry. You said how to move it to a -- we don't know. I mean, it -- as it develops, we'll adjust.

But Mr. Evans on the costing side.

MR. EVANS: Yes. And I agree with everything Mr. Grubb said.

I would also add that the declining revenue requirement nature of the infrastructure invested, those revenue requirements will go down over time. But that revenue will at least stay there or increase over time. So all things being equal, the downward pressure on rates will increase from what we filed.

COMMISSIONER PRIDEMORE: So part of this filing has a good amount of renewables in it. And is it --

I'm certain everybody that's involved in and lives and breathes this, as some of us do, part of the reason for this filing is because we have to have baseload. And we have to have baseload because of the amount of renewables we've put into the system.

I see all four of you are nodding your heads yes. Okay.

MR. GRUBB: Well, so --

COMMISSIONER PRIDEMORE: So --

MR. GRUBB: Go ahead, Commissioner. I'm sorry.

COMMISSIONER PRIDEMORE: -- why -- what -- I guess my first question is: Is why did Georgia Power commit to more renewables, instead of what is firm capacity and -- and what can be dispatchable and used to go with the -- what is now the fourth largest state in the nation in solar?

MR. GRUBB: So I -- we -- we aren't requesting new renewables in this filing for the purposes of serving capacity. The new renewables we're requesting are to charge the battery energy storage systems. So all the resources that we're requesting are for serving the capacity.

So you've got the PPAs, which -- which are dispatchable resources that can do that. You've got the CTs, which are going to be very important for

cold mornings like today and tomorrow. They're dispatchable resources.

And then we have battery energy storage systems. We're putting those at solar facilities to use the solar to charge them. And you're basically firming up that solar.

So we're not asking for any new renewables from the purposes of requesting renewables for energy savings like we've done. We've got all the RFPs coming out of the 2022 IRP. So the only renewables that we're asking for here are for the purposes of charging the 200-megawatt batteries.

COMMISSIONER PRIDEMORE: I guess my question to that is: Why wouldn't we put the requested BESS with existing renewable assets, which you are?

MR. GRUBB: We are.

COMMISSIONER PRIDEMORE: But why wouldn't all of them go there?

MR. GRUBB: Well, they're -- originally they were added for energy purposes. So Robins and Moody's were part of: Let's add solar because there's benefits to solar from an energy standpoint. And part of the early -- early move in the state for Georgia to own and build at the military sites.

And so those are the sites that we'll look at.

Mr. Bush and team are looking at additional battery sites and we're looking at ours and third parties'. So it is looking at doing that.

So it's really because those solar resources that are existing have always been done from an energy-savings standpoint. Now batteries are a capacity resource. So the -- when we look at we need capacity to serve capacity needs, solar alone is not the resource that we look to do that.

It's an energy resource that we add. They all work together, but that's why.

COMMISSIONER PRIDEMORE: You said a lot there, Mr. Grubb. So there's -- there's no -- I guess, go back -- going back to my question.

Why would we not put all of the BESS that's in this filing with existing solar properties all across the state? Existing utility-scale or DG.

MR. BUSH: Well, Commissioner, we really -- for the -- for the Robins and the Moody batteries that we're requesting, we are putting them at existing solar sites. With the BESS -- the 200 BESS, we are requesting 200 of solar, as well. So, effectively, it is solar and BESS combo.

And we've engaged other developers that have PPAs with Georgia Power Company to see if there is

availability at their sites, to see if there -- that they do have a desire or a willingness for us to be able to deploy batteries at those sites.

So we actually are doing that, Commissioner, because your -- your insight is correct. Those are -- we know we have transmission available to deliver that capacity. So that's one of the reasons why we feel like BESS at solar sites is a great option.

MR. GRUBB: And, Commissioner, I would add we've got the -- the All Source RFP for capacity purposes coming up that will address '29, '30, and '31. And -- and bidders and developers can submit bids with batteries that are at their solar facilities. We -- we were saying standalone storage or standalone, plus renewables. But I think the -- the rest of the market could look at it, too, and we'll continue to look at it as a company, as well.

COMMISSIONER PRIDEMORE: All right. My last question for now. I've -- I've read your filing, I've read your testimony, I've discussed this with people at Georgia Power.

Talk with me about why I should have any confidence whatsoever in these projections when the 2022 projections were so off.

MR. GRUBB: So I would -- Mr. Valle can talk techniques on the forecasting side, but I -- Commissioner, the real thing -- the real reason is because this forecast is based on tangible projects that are looking at the state.

We have -- we have real data. We have real customer information on their ramp rates. So it's -- it's not just an economic projection that might be like an economic data series.

We've got a pipeline of almost 20,000 megawatts of projects that are looking at the state. And so we're -- we're well below half of that in the forecast, taking into consideration the risk. So it's based on -- on real projects, real data, tested mathematical processes.

And -- and from a forecasting standpoint, I believe we report in the IRP, we -- we've been close, within a few percentages, on all of our IRPs and we've provided the -- the performance level in the forecast. It comes back to just this is a generational change in this whole move in the economy.

And, again, five other companies are facing the same thing. It's a national issue. So I would say because the fundamental forecast hasn't changed.

We've done external adjustments before. This is just a lot wider range of it.

But I would really come back to the -- it -- the state is -- is booming. And I think that's known. So that's -- that's where I put the confidence is that we know all that activity.

I don't know if you want to add anything.

MR. VALLE: Yeah. Just -- just to add a couple of -- a few things. I think what we have put together is very reasonable.

Again, to reiterate the point that Mr. Grubb was -- was using, the amount -- the size of the pipeline out there is huge. It's about the size of what we have to serve today; right?

Our recommendation, our -- our estimation of the load that we have to serve with a high level of confidence is less than half. So from a -- from a sizing perspective, seems very reasonable.

The other piece is that it's based on facts. It's based on customer information. It's including and considering the uniqueness of this portfolio.

So we have large loads. In the past, planning for -- for load was kind of like an average, if you would, process in the -- in the sense that you would look at historical trends, you would continue

those -- those trends, then everything would be captured within that.

Now, a single customer sometimes is larger than what the baseline -- the complete baseline forecast could capture. So we're talking about developments that forces us to think: What would I do as a -- as Georgia Power to ensure that we reliably serve these customers if they come or not?

And in order to do that, we have developed this approach that -- it doesn't consider just a single expectation. It -- it works on a hundred thousand different combinations of customers selecting Georgia, customers not selecting Georgia, and -- and analyzing each one of those cases for the informed decision.

COMMISSIONER PRIDEMORE: But, Mr. Valle, you said that you did -- you did it the same way in 2022 when it was so off. So I guess my point is: Is, you know, like -- like we've been discussing, we have -- we have 14 committed new customers. We have 51 noncommitted customers at varying projections as to whether or not they'll become a Georgia Power customer.

MR. VALLE: Yeah. Just -- just to be clear --

COMMISSIONER PRIDEMORE: It's -- I mean,

there's -- you can say I'm making your point for you. I say, on the other hand, that -- that perhaps the projection is far too wide.

MR. VALLE: I -- I would -- I would disagree with that. But -- but let me clarify that in 2022 we did not have anything in the state history or the company history to anticipate and foresee what we're seeing today. It is completely unprecedented.

At the time, if we would have been looking at any potentials in areas for what we have today, it would have been widely speculative because we did not have information. We did not have facts.

What we have today is customer information. So we're not -- we're not hiring a consultant really to -- to create and capture this information. These are direct negotiations and conversations with customers.

We capture that, we inform the forecast, and we give you a -- the best recommendation that -- that we have with the information available to you. It's a very reasonable expectation of the load that we have to serve and -- and although higher than anything that we have seen before, this -- this external adjustment for large loads, it represents a reasonable expectation of the future load we have to serve.

MR. GRUBB: And, Commissioner, again, there -- there's several other companies that are seeing the same thing. That is, this is an industry issue of -- of this rapid increase in the need for electricity demand.

COMMISSIONER PRIDEMORE: With all due respect, Mr. Grubb, I'm not seeing this level of request coming out of Duke, NextEra, or like utilities. The -- the breadth of -- of this request is -- is what I --

MR. GRUBB: Yeah. I don't -- I don't remember their --

COMMISSIONER PRIDEMORE: -- I'm questioning.

MR. GRUBB: I don't remember their megawatts. But I do know that -- that they were having to update their planning in the same fashion that we are.

COMMISSIONER PRIDEMORE: That's all I have, Mr. Chairman.

CHAIRMAN SHAW: Any other questions, Commissioners?

(No response.)

CHAIRMAN SHAW: All right. We'll move on down the list of appearances with cross, starting with Georgia Public Service Commission.

MR. THOMAS: Thank you.

CROSS-EXAMINATION

BY MR. THOMAS:

Q Good morning, panel.

A (Witness Grubb) Good morning.

Q Preston Thomas on behalf of PIA staff.

I just wanted to follow up with a few questions asked by Commissioners. I wanted to start with a question that Commissioner Pridemore asked about the high-risk crypto companies. And I think you said that you've identified two as being high-risk.

Are those inside the Georgia Power territory?

A (Witness Valle) I don't have the information in front of me. We can get -- we can get that.

MR. THOMAS: Okay. Yeah, I'd -- I'd like to make that a hearing request.

BY MR. THOMAS:

Q And then I wanted to -- to go through a series of questions to understand how you arrived at the conclusion that there would be downward pressure on rates and no overall rate impact from this proposal. But -- but first wanted to just start by asking some follow-up questions from Commissioners.

When Commissioner Shaw asked you about downward pressure, just to -- just to make sure I understand, are you saying that downward pressure on rates -- are you talking

about the average over the life of the asset or no upward pressure in the short term, say five to ten years?

A (Witness Grubb) So that's in the short -- well, over the life is -- is part of what we do in the RIM test, but it's both.

And so the -- the data response to DEA 3-6 shows in the short term that the revenue requirements from these resources is more than made up for by the revenue from this -- these loads. So it's -- it's immediate.

Q And -- but all customers are paying for new generation capacity and transmission costs; right?

A (Witness Evans) Well, I would say that the revenue requirements are reflected in our books and records, like all of our revenue requirements are. But the revenues that are associated with this request for these new customers outweigh and exceed the revenue requirements requested in this case. Therefore, all things being equal, that we would have additional revenue outweighing the revenue requirements, putting downward pressure on rates.

Q So looking at the RIM test that the company has preferred -- performed, it looks out for 30 years. And so, obviously, there is -- there's some risk in 30-year projections.

If the actual results turned out to be different than the company's projections, could that result

in the incremental cost to serve new customers being higher than the revenues that the company projected that it would receive from those new customers?

A (Witness Evans) Well, the -- the rate impact measure test, which we've used for decades, is -- can be measured up to 30 years. But not every analysis is 30 years, by any means.

And as I mentioned to Commissioner Pridemore earlier, the realtime pricing program at Georgia Power is such that the marginal cost to serve the load are reflected in those price signals. So, absolutely, the projections can change over time. But to the extent that our cost to serve customers changed, those associated revenues will change, too, because the price matches the cost for the realtime pricing program.

So there's a self-adjustment almost, if you will, such that if those projections deviate up or down, the revenues will go up or down with them.

Q So are you saying that there's not a scenario where if the projections are wrong that it could result in costs being higher to serve customers than the revenues that the company has received from those customers?

You can't imagine a scenario where that could happen?

A (Witness Evans) I think it's important to

realize that the cost to serve the customer are an important part; right? But we also ensure that the revenue doesn't just recover our cost, but puts downward pressure on rates.

So we're not just making offers that are at the cost to serve; right? That's the -- that's the starting point. That's the most important part. We're also ensuring that these -- these offers put downward pressure on rates and benefit all of our customers.

Q So I -- I just want to make sure. Are you saying, no, you cannot imagine that scenario?

A I think we've mitigated that risk significantly.

Q Is a potential additional source of future pressure on the company's revenue requirement is that the company is requesting the authority to defer costs by recording them as regulatory assets, which would then need to be addressed in the next rate case?

A (Witness Grubb) So could you -- could you ask it again, Mr. Thomas? I just want to make sure I've -- you're talking about the deferral on the cost, but I missed your initial question.

Q Well, could that be a source of potential pressure on the company's revenue requirements?

A (Witness Grubb) So those -- those deferrals were captured in the analysis that we did. So, again, we're

looking at the revenues outside of this current rate plan from these increased loads and the -- the revenue requirements from these resources, including the deferrals, and it's still downward pressure on rates.

Q And to Commission Pridemore's question, for this downward pressure to occur, all this new load has to materialize; right?

A (Witness Grubb) So not all of it. What we've -- what we've done in that analysis is we looked at -- Mr. Valle's talked about we have a -- a range of external adjustments. We are planning for the forecast in this IRP update because that is the load we expect. But we did take a lower level of revenues when we compared it to the costs. So we did put some lower revenue values in there and it still was downward pressure on rates.

So to Mr. Evans' point, just a way to mitigate some of that risk.

Q The company's 2023 IRP Update also includes requests for new additional sums. And additional sums have been allowed by the Commission for items such as renewable purchase power contracts in the past and represent an element of profit to the company over and above the cost of PPA; right?

A (Witness Grubb) Yeah. So additional sums allowed by law. And we have recovered those on renewable

RFPs, but also capacity PPAs and demand-side measures.

And so what we've requested here, since we just got out of the 2022 IRP and went through the additional sum, was to be consistent with what was done in the '22 IRP.

Q And one example of an additional sum that's new is on the proposed capacity purchase from the affiliate Mississippi Power; is that right?

A (Witness Grubb) I would not agree that that is new. We've gotten PPAs on all -- we've gotten additional sum on all PPAs, including our affiliate Southern Power.

Q But -- but that's what you're requesting here, right, an additional sum on the proposed capacity that you're going to purchase from your affiliate?

A (Witness Grubb) Yeah. Consistent with the same treatment we got in the 2022 IRP.

Q And if that additional sum is approved, the company's ratepayers are the ones that end up paying for that additional sum amount; right?

A (Witness Grubb) So like all additional sums allowed by law, customers do. Again, we've captured that impact in all of the economic analysis in the filing, including the statement of downward pressure on rates.

Q And I wanted to see if we could walk through each of the new regulatory assets that the company is requesting in the IRP update.

A (Witness Grubb) Okay.

Q The company is proposing a new regulatory asset to defer capacity and nonfuel energy payments under the Mississippi Power PPA; is that correct?

A (Witness Grubb) That's correct.

Q All right. And the company is proposing a new regulatory asset to defer capacity and nonfuel energy payments under the Santa Rosa PPA; correct?

A (Witness Grubb) That's correct.

Q Okay. And the company is requesting a new regulatory asset for development costs not used or transferable for the 1,000 megawatts of battery energy storage or BESS costs; is that correct?

A (Witness Grubb) That's correct. If they're not approved, then we would request to approve those.

Q And the company is also requesting a regulatory asset for development costs not used or transferable for the 1,400 megawatts from the combustion turbine generation units; is that correct?

A (Witness Grubb) That's correct. Again, if the resource is not approved, we are requesting that, correct.

Q Okay. And also requesting a new regulatory asset for development costs for flex capacity; is that right?

A (Witness Grubb) If we incur those, that's

correct.

Q And is that the totality of the new regulatory assets being requested by the company?

A (Witness Grubb) That's correct.

Q And what is the -- do you know what the maximum amount that the company expects it could be deferring in 2024 and 2025 if the company's requested regulatory assets were to be permitted?

A (Witness Grubb) So the deferrals for the PPAs are known and they're provided in some data requests and are included in the DEA -- Staff DEA-3-6. They're included in that analysis. And so there's a figure there. I can't remember it, but it is in there.

From a development standpoint, it would depend on the timing of when the decision was made by the Commission. The reason we're asking for those deferrals, Commissioners, is because these resources are being added to meet capacity needs in '26, '27, and '28 and were not, you know, contemplated -- these load growth was not contemplated in the 2025 rate -- the '22 rate case.

Q So no one on the panel knows the total number then?

A (Witness Grubb) I think it would be trade secret, too.

Q Okay.

A (Witness Grubb) I mean, we are not trying to hide from it, obviously, Mr. Thomas. I think it's in some of the data requests that we have gotten. Definitely the capacity cost for the PPAs, which, importantly, also include revenue -- revenues that we've gotten from selling those resources to other entities.

So we're reducing that deferral from revenues we're getting through a sale to another wholesale entity. I just am not sure what the value is and I can't remember the development part of it, so...

Q Okay. And would you agree that the standard form for addressing regulatory accounting treatment is in a rate case?

A (Witness Grubb) I think -- yes. Rate-making procedures are handled in rate cases. But deferrals in IRP requests are nothing new. We've done that for several of the last IRPs.

Q All right. And the Commission's decision in Docket 44280, the company's 2022 rate case, approved a settlement agreement that established a three-year rate plan for the company that covers years '23, '24, and '25. The return on equity earnings ban established in that docket is 9.5 to 11.9; correct?

A (Witness Grubb) I wasn't involved in the rate case. But, yes, that sounds right to me.

Q Okay. And the company files an annual surveillance report with the Commission; correct?

A (Witness Grubb) That's correct.

Q And as long as GPC has earnings in a year that are within the earnings ban, no rate adjustment occurs; right?

A (Witness Grubb) That's my understanding, correct.

Q In the current '23 IRP Update filing, not requesting any decisions on amortization periods or regulatory treatment of any of the proposed regulatory assets; correct?

A (Witness Grubb) Yeah. No change to the outcomes from the 2022 rate case.

Q Is the company opposed to addressing any amounts related to new regulatory assets recorded in '24 and the context of the '24 ASR?

A (Witness Grubb) So what we're asking for is deferral to the next rate case. Because, again, these are -- this amount of load growth and these resources being needed were not contemplated in the 2022 rate case.

And so like other deferrals we've done, I think one of the tax acts a few years ago, and then also COVID, we have deferred things to a following rate case that weren't considered in setting the 2022 rate case. So the company's

position is to defer the costs from these resources to the years in which they are needed, which will be addressed in the next rate case.

Q I wanted to ask a few more questions around new capacity from your affiliate Mississippi Power.

A (Witness Grubb) Okay. Uh-huh.

Q In order to serve the increase in new load that the company is expecting from choice customers, the company wants to obtain that additional capacity from its affiliate Mississippi Power; right?

A (Witness Grubb) That's one of the resources. And I would say it's the whole load forecast. We're looking at the load forecast includes the needs of all customers.

And so, Commissioners, what we did when we saw the capacity need year move, we went to the resources that we knew could serve those times quickest. And so Mississippi had some length in the system and so that's why we entered that PPA.

Q And currently Georgia Power and Mississippi Power are both part of Southern Company power pool and can share energy through the intercompany interchange agreement; right?

A (Witness Grubb) Yeah, we can. I think the important point there, Commissioners, is it's -- when you look at reserve sharing, it's temporary. The IIC is through

contemporary surpluses.

The issue with Mississippi was, from a Southern pool standpoint, Mississippi's customers did not need those resources. And so Mississippi and their Commission had plans to retire out of some of their -- their capacity or to sell it. And so to keep it in the pool for Georgia Power's purposes and serving our loads, we entered the PPA.

Q All right. But when Georgia Power obtains energy or capacity from Mississippi Power through that interchange agreement, there is no additional sum charged to ratepayers; right?

A (Witness Grubb) No. It's a market reserve sharing price. But, again, through the reserve sharing, that's usually a month-to-month-type arrangement. We may buy one month; we may sell one month.

And so from a PPA standpoint, requesting additional sum because it benefits customers is for us to make sure that that 750 megawatts stays in the pool through 2028.

Q And just in response to a question, I heard you say that you wanted to defer costs that you didn't anticipate in the 2022 rate case.

Were there any revenues that you didn't anticipate in the 2022 rate case and would you defer those, as well?

A (Witness Grubb) So we don't know what those revenues will be, if they do occur, to be higher than what was in there. They're not the revenues associated with loads that are driving the need for the capacity.

And so we don't know what those revenues will be. Most of this load is not online yet and it -- it's driving that need and capacity into '26 and '27. That's why we're deferring the cost.

Q Okay. And although when Georgia Power obtains energy capacity from Mississippi Power through the IIC, there's no additional sum, in this case you're proposing an additional sum of $3 a kilowatt year for the PPA with Mississippi Power?

A (Witness Grubb) Yeah. Again, to be consistent with what was done in the 2022 IRP, that's a PPA that benefits Georgia Power's customers by making sure that we've got 750 megawatts of load that can serve customers through the end of 2028.

Q And Georgia Power doesn't expect to need the additional 750 megawatts of capacity in '24 or '25; is that right?

A No. You're always more reliable when you have more megawatts on the system. But both -- for Mississippi, they were going to retire some units at the end of the prior year and look to sell those.

And so we needed them for '26, '27, and '28, but they wouldn't have been there if we had waited until '26, '27, or '28. So we -- we bought all five years.

Q Okay.

A (Witness Grubb) And -- and all of that is considered in the economics that we've provided and the statement of downward pressure on rates.

Q Okay. But although you don't need the capacity in '24 or '25, you're still proposing to charge ratepayers for an additional sum in '24 and '25; correct?

A (Witness Grubb) Consistent with the 2022 IRP.

And I think another thing that's important, Commissioners, we have sold 500 megawatts of that 750 megawatts for the first years when we don't need it to be above our target reserve margin. And we're continuing to look to sell the other 200. And we'll do the same thing on Santa Rosa.

So to Mr. Thomas's question, the capacity need is '26, '27, and '28. For '24 and '25, we'll look to sell as much of that as we can.

VICE-CHAIRMAN ECHOLS: Do our customers receive a benefit from that sale and does it offset the additional sum?

MR. GRUBB: It -- it does. So, yes, customers get that back. So on the deferrals that we're

speaking to, the revenues from those PPAs that we're paying the counterparties, we will net that against the revenues we get by selling to others.

Pricing-wise, they're pretty close. The -- the additional sum is a 15th of the annual capacity price of those PPAs, but they're close. I think they cover most of it.

BY MR. THOMAS:

Q So, just to be clear, did you say it does offset the additional sum or you're not sure?

A (Witness Grubb) I've -- I know the capacity price are close. I'm not sure it directly does it. But, again, the -- the benefit to customers even in those first two years is the ability to have those resources for the three years in which we need them.

Q Could -- could we find out if it offsets the additional sum?

A (Witness Grubb) We could, yeah.

MR. THOMAS: I would make that a hearing request.

BY MR. THOMAS:

Q In your response to data request SDF-LA-1-4, Parts B and C, you say that Georgia Power doesn't have an accounting information related to Mississippi Power generating units that would comprise the new PPA.

Did Georgia Power ask Mississippi Power for any accounting information in the negotiations of that 750 megawatts?

A (Witness Grubb) Do you have that data request? I don't -- I don't have it with me. Because I know there was some asking for some information that we don't have and doesn't impact the PPA.

Q I've got a large pile of data requests here but I don't see that one.

A (Witness Grubb) Well, there's a lot of them. I get it.

Q Yeah.

But, in general, in the -- in the negotiations, do you know without specifics if accounting information was requested of Mississippi Power?

A (Witness Grubb) I -- I don't recall any.

And, Commissioners, I think one thing that's important to know is that the purchase for Mississippi Power is for 750 megawatts from their system. It's not tied to any specific unit. It's just the 750 megawatts in the pool will be Georgia Power's capacity and not Mississippi's capacity.

So I'm not sure what kind of accounting information we would have -- would have needed for that type of a sale. But I just can't speak to it. I can't remember

the DR.

Q Does Georgia Power know how much energy and capacity it obtained from the IIC?

A (Witness Grubb) I can't remember if we provided that in a DR. I mean, we have that. Again, it depends month to month, day to day between all the different companies.

Q I don't think we got that in a data request. Is that something I could request?

A (Witness Grubb) So, again, you're -- you're asking for --

Q For the amount of energy and capacity obtained from an -- from the IIC.

A (Witness Grubb) In total; not in total?

Q In total and -- yeah, in total.

A (Witness Grubb) Yeah. We'll -- any certain time period or --

MR. HEWITSON: I -- hold on.

MR. THOMAS: For what time period?

MR. GRUBB: Yeah.

BY MR. THOMAS:

Q I guess I don't have a specific time period that -- I guess what we're -- we're trying to understand is, you know, how much capacity is obtained through the IIC.

You know, does it -- does it come close to the

type of capacity that you're talking about getting through a PPA?

I guess, can you -- can you answer that question?

A (Witness Grubb) Yeah. I mean, I don't -- I don't know. You're talking about a --

Q So you're asking --

A (Witness Grubb) -- 30,000 megawatt system, so --

Q Right. So you're asking for 750 megawatts through the PPA, instead of using the IIC. But is -- is that because you can't get that kind of megawatts through the IIC or -- or why can't the IIC --

A (Witness Grubb) Okay. I see what you're saying.

So -- so the reason that we've -- we've entered the PPA is because, again, when we looked at needing to meet these loads, there was system length. But there's no obligation from one operating company to maintain resources in the pool for the others. It's temporary and it's there if you need it.

But Mississippi and their Commission had already decided for Mississippi's customers they didn't need those megawatts to serve Mississippi. And so when our -- our needs year changed, we reached out to Mississippi to make

sure that those megawatts stay in the pool.

But you have to have the PPA to give Mississippi certainty that they would -- that they would have recovery and for us to have certainty they would be there. If we just assumed that reserve sharing was going to happen, their loads -- their resources may have left or we may have done something and they wouldn't have gotten any revenue. So really it's just a way to kind of, for lack of a better term, lock in that reserve sharing.

Reserve sharing is very beneficial to pools, very beneficial to the operating companies. The temporary surplus and -- and deficits is more of -- like, for instance, us coming out of the '22 IRP, we had some length, but that length was important to get us to where we have capacity needs. Mississippi was going to be long for a long time.

And so that's the reason for the PPA. So, Mr. Thomas, I mean, the -- I don't know monthly how much is -- is exchanged in the reserve sharing, but it could be that magnitude. But the main point is when we look at the reserves on the system to serve load, we needed to keep those Mississippi units. And so that's why we entered the PPA.

Q Okay. So going back to my request, maybe I could have a request over five years. That would give us a

reasonable view of --

A (Witness Grubb) Like through '23?

Q Uh-huh. That would give us a reasonable view of what that looks like.

All right. I'd like to turn and ask a few questions surrounding the Commission's role requiring the company to maintain a minimum percentage of self-owned rate-based assets.

A (Witness Grubb) Right.

Q The company assumes in its filing that it must follow the 70 percent rule in selection of new resources. However, when you read the Commission rule, would you agree that it anticipates that the percentage may be changed from time to time and offers the Commission the ability to suspend the rule?

A (Witness Grubb) Yeah. So the -- the -- having a minimum of purchase power is actually part of the law and the rules, but the amount is set through a Commission motion in 2001. So the Commission does have the authority to change that.

We think it's appropriate where it is. And so 70/30 has never come up much because usually with flat load growth. It came up a little bit in the '22 IRP. Usually your PPAs drop off when you have a need. But in this situation, that's not the case.

So, yes, they have the authority to change that, but we think it's at an appropriate level. Because both ownership and PPAs are important.

Q But the Commission could lower that 70 percent threshold if they concluded that ratepayers could be served reliably, but more economically, with a different ratio; right?

A (Witness Grubb) They -- they could. I would say in this case we went to the market first and got system length from Mississippi and Santa Rosa and that was all we could get. And so the ownership was crucial for us to be able to meet the needs of this filing.

And so 70/30 is a consideration and it's important, but the -- the driver for ownership in this case is to be able to fully resource by the time we need them.

Q If the contract with Mississippi Power pushes the company below the 70 percent target, then the Commission could take into account the fact that Mississippi Power is an affiliate when deciding whether to address that 70 percent; right?

A (Witness Grubb) They could. Again, those -- those units are under Mississippi's control and Mississippi's decisions and their Commission and not this one. And that's why we differentiate it from -- from Georgia Power.

Q But you don't think that the relationship of being an affiliate changes the dynamic between a nonaffiliate PPA?

A (Witness Grubb) From a -- from an affiliate standpoint, we've never differentiated in RFPs between Southern Power either. They're part of the pool, as well. Not coordinated the same way, but they're part of the pool. But, I mean, the main driver here is the ability to -- to get those resources and be there.

So I don't think that's a -- a level you want to change periodically either, the 70 percent. I mean, it was put in place for reliability concerns is my understanding. And so we -- again, yes, you have the authority to change it, but we think it's at an appropriate level because ownership is still very vital to today in the fleet.

Q Okay. But the Commission could decide that although ownership is vital, the exact number could change if other factors pointed that reliability could still be maintained; right?

A (Witness Grubb) Again, that's the Commission's authority. That PPA does end at the end of '28, though.

Q And if the company couldn't add enough self-owned capacity to meet the new load growth, do you believe the Commission should let the 70 percent target stand in the way of serving new load in a timely manner?

A (Witness Grubb) I'm sorry. Can you repeat the question?

Q Sure. If the company can't add enough self-owned capacity to meet the new load growth, do you believe that the Commission should let the 70 percent target stand in the way of meeting new load growth in a timely manner?

A (Witness Grubb) I don't think they -- they would. I mean, the -- the main thing in this case is the market. There are no existing market resources that can meet the needs in this case. And so, again, if the company can't develop them, we just -- we won't be able to have the plan.

So the -- the RFP coming out of 2022 is going to set us up well to handle needs for '29 and beyond. But, again, if there's marketing resources, we're not aware of them.

CHAIRMAN SHAW: Mr. Grubb?

MR. GRUBB: Yes, sir.

CHAIRMAN SHAW: You know, when you're talking about resources that were available, I know you guys started out this process with a request for information to gather that -- those resources.

So did you find that some of the resources that may have been available at some point were already

taken advantage of by some of the other electricity providers in the state --

MR. GRUBB: Yes, sir.

CHAIRMAN SHAW: -- that are not subject to the same regulatory authority?

MR. GRUBB: Yes. A lot of -- a few things there, Commissioner, but you're right. So I would -- I would actually say, you know, the first mover to the market was Georgia Power and this Commission. When we did the '22 IRP and those 2,300 megawatts of resources that we got, those six PPAs, that was the first move to get resources from the market in case we retired coal units.

But, you're right, since then, with other coal retirements and other entities looking at it, this increase in demand -- and then also a lot of entities have raised their winter reserve margins, especially after Winter Storm Elliott. So, yeah, Oglethorpe Power has bought 1,300 megawatts from the state.

We know that TVA had RFPs. Santee Cooper has RFPs. Alabama has RFPs. And so we did the -- we approached Santa Rosa. We knew of them through our commercial operations group and we approached them to see if they were available. We approached a few others and they weren't. And so, yeah, the market --

the market is -- there's not a lot there.

The RFI was for -- for two reasons. It was for this period and it was also for the period that's going to be covered by the All Source, but it did not indicate any other existing assets out there.

CHAIRMAN SHAW: Thank you.

BY MR. THOMAS:

Q I want to turn to page 37 of your direct testimony and ask you a few questions around the BESS construction.

A (Witness Grubb) You said page 37, Mr. Thomas?

Q Yes. That's right.

A (Witness Grubb) Of direct testimony?

Q That's correct.

A (Witness Grubb) Give us just a second.

Q Sure.

A (Witness Grubb) Okay. Which lines? We are on page 37.

Q Well, I will reference the topics on page 37, not a particular line.

A (Witness Grubb) Okay. Just -- okay. I'm sorry.

Q But I guess we can start with line 9, where you say: The time to construct BESS is shorter than other types of generation, and, therefore, can be more quickly deployed

to help meet earlier capacity needs identified in '23 update.

And -- but isn't it true that the company currently only has one battery project expected to come online and the company's approximately six months behind bringing Mossy Branch online relative to the original time frame?

A (Witness Grubb) So I'll -- I'll let Mr. Bush -- Mr. Bush speak to -- to Mossy Branch.

But, Commissioners, what -- for the reason we looked at BESS, in terms of meeting these needs, again, when the need year moved up three years, there's not enough time to do an RFP. We looked at system length, market.

And then once we exhausted those, we looked at what can you build the quickest. And it's batteries, especially at locations where you don't have to have further transmission projects. Because batteries have to load -- have to have the charge and discharge if they are standalone. So we specifically identified those. And then CTs that we could build.

So in terms of the timing, I'll let Mr. Bush speak to -- to Mossy Branch, but I wanted to give y'all a reason of why we looked at batteries.

A (Witness Bush) So Mossy Branch, as you -- as you recall, Commissioners, you approved in the 2019 IRP 80

megawatts of battery projects for Georgia Power Company. And at the time of that approval, we didn't have a final strategy around how many -- how we would deploy each of those types of batteries.

So part of the time frame for us between today -- to where we are today, having constructed Mossy Branch, and where we were, was, first of all, developing the strategy around how we would deploy and what the configuration of the different projects would look like.

The other thing that I think is very important to remember is we did go through a worldwide pandemic. In dealing with that issue, those were issues that we had to deal with as we engaged others in the marketplace, the uncertainty around equipment. Long lead times have changed significantly for things like transformers and high-voltage breakers. So all of that has added to the time frame.

But if you think about it, we're four and a half years. We began the construction, actually, of Mossy Branch in March of 2023 and we -- we expect full mechanical completion of that resource by the end of this month.

So you're talking about nine months to actually construct a resource, a full utility-scale battery. And so we feel like Mossy Branch has gone well and it's a great example. And we've learned a lot of lessons through that process so that we will be able to deploy the incremental

batteries that we're talking about here in this hearing.

CHAIRMAN SHAW: So of that -- of that 80 megawatts you talked about from the pilot in the '19 IRP, I just remember the first -- I think there was a 65 megawatt project that you --

MR. BUSH: That's what --

CHAIRMAN SHAW: -- brought to us first; right?

MR. BUSH: That's right. Mossy Branch is the 60 -- is 65 megawatts, that's right.

CHAIRMAN SHAW: If I recall, the cost on that was around 110 million. Does that sound --

MR. BUSH: But --

MR. GRUBB: I can't remember what --

MR. BUSH: I actually don't remember what the cost --

CHAIRMAN SHAW: Let me just -- let me just ask you this then. I can remember numbers. I think I'm right.

MR. GRUBB: We're not doubting you.

CHAIRMAN SHAW: I guess what I'm saying is -- what I want to ask is this: You know, that -- that was a pilot and you said a lot -- a lot was learned from that?

MR. BUSH: That's right.

CHAIRMAN SHAW: How much have you learned in

terms of have these -- this technology -- has this technology become more competitive, more affordable since then?

Because that -- that was an expensive project in my mind.

MR. BUSH: Yes. Yeah. Actually, several things have happened since that -- since that, Commissioner. A lot of lessons learned and they have become much more economic.

One of the earlier speakers talked about the Inflation Reduction Act and it does allow us to actually capture a 30 percent investment tax credit that we actually will pass directly on to our customers.

So while Mossy Branch initially was deployed at whatever that level, if it was 110, we're now going to be able to capture production tax -- I'm sorry -- investment tax credits that will lower the overall cost to our customers even for deploying that project. So that's one of the things.

You mentioned -- I just went brain dead on your -- your question.

MR. GRUBB: The other -- the other projects.

Were you asking about beyond Mossy?

MR. BUSH: Oh.

MR. GRUBB: Yeah.

CHAIRMAN SHAW: No. I was mainly just trying to see what -- how much more economical this technology has become since then. I'm assuming it has.

MR. BUSH: It -- it actually has. The demand is driven --

CHAIRMAN SHAW: Not counting the 30 percent --

MR. BUSH: That's right. So the other pieces of that -- thank you, Commissioner -- is demand -- the -- the technology itself has been driven mainly by electric vehicle deployment.

And so a lot of the technology itself -- early on deployments of batteries were nickel metal cobalt-type technology. We've moved to now a lithium iron phosphate technology that is more stable, has higher cycling capability, can handle temperature changes significantly better, a longer life, different degradation. So those are all maturities that are happening in the technology.

The other aspect of the technology from a reliability perspective today -- and if you look at just Texas and California, there's over 10,000 megawatts of batteries deployed and in operation and reliably performing today. And in just

those two regions, they have in the plan over 75,000 megawatts that's planned to be deployed.

So the technology has come a long way. We have a lot of confidence in its ability to be reliable. And it is being relied on by -- by many other regions today.

CHAIRMAN SHAW: Thank you.

BY MR. THOMAS:

Q So, Mr. Bush, you pointed to Mossy Branch, despite being, you know, six months behind schedule, as being successful.

Would you agree, in general, that the company has limited experience for building BESS?

A (Witness Bush) No, I actually wouldn't agree with that.

Commissioners, I would say it was actually the foresight of this Commission maybe ten years ago or so that allowed Georgia Power to have its first battery deployment. If you remember in 2016, we actually deployed a 1-megawatt, 2-megawatt-hour battery in Cedartown, Georgia. And that actually began us down this path of beginning to learn more and more about batteries. Your 2019 approval of those 80 megawatts, we, again, began to learn more and more.

The other thing is that Georgia Power is not just a standalone utility. They get to get lessons learned from

some of our other operating affiliates. One of those is Southern Power Company.

They've had large utility-scale batteries in operation since 2021. So for several years they've actually been operating and maintaining those batteries. So Georgia Power gets those learnings and is able to apply them to everything that we deploy here.

Q So you're pointing to affiliates as having the experience?

A (Witness Bush) I would say affiliates do, but so does Georgia Power Company. Again, the early deployment of battery at Cedartown of Georgia was one of the first utilities to do that. And moving from there to Mossy Branch.

Lessons learned are not just when they go into commercial operation. There's a lot of lessons to be learned from early deployments in the development process itself. So Georgia does have a lot of development experience and will soon have significant experience in just the next few months when Mossy goes into operation.

Q The company made a similar request in the '22 IRP for the authority to develop 1,000 megawatts of battery capacity. Staff opposed that proposal in part because the company had, in staff's opinion, not demonstrated that the company ownership would be any better than third-party

ownership and that third-party ownership might be more cost-effective for customers.

Can you tell us why you think company ownership could be more cost-effective?

A (Witness Grubb) Well, so -- so, first, I'll let Mr. Bush chime in there, but we did also get approval on that same docket for McGrau Ford.

Q Uh-huh.

A (Witness Grubb) So it was -- it was -- we asked for 1,000, we got 265 at McGrau and a 500 megawatt RFP, so...

A (Witness Bush) Sure. And from a -- just the efficiency of deployment and operation, anytime a company owns an asset, it's able to utilize all aspects of that asset as flexible as the asset can be. And so really what we see from batteries in particular, they can provide a number of different services for the -- for our companies.

It's a capacity resource. It's an energy resource. During peak periods, we expect it to be able to carry reserves across the peak because it can respond within cycles almost instantly to contingencies on the system.

And so as the system -- the characteristics of the system change, I don't have a contract that may not allow me to have the flexible use of these resources. So as ownership, I get both the flexibility and the full

reliability of the resource.

VICE-CHAIRMAN ECHOLS: Let me ask you about the -- the hyperscale data centers that are coming that you've got on your list.

They're doing a hundred percent backup, right, at a data center?

MR. BUSH: A lot of them are, yes.

MR. EVANS: Yes, sir.

VICE-CHAIRMAN ECHOLS: And with the program that we approved, you know, not too long ago, can we -- are they interested in working with you and allowing us to tap those assets, to have a view into those assets, to maintain them, or is that just too -- too important to them?

MR. EVANS: No. We're in active conversations with a number of them, specifically with the programs that we proposed in this IRP update.

For the programs that were proposed in the 2022 IRP, marginal load is ineligible for that. So that was more of a demand response, using those backup resources for demand response.

These new programs positioned as supply-side programs, customer-sided supply-side programs providing those host customers resiliency services has generated a lot of interest in -- in those types

of customers that are bringing these types of resources to the state anyway. And it allows Georgia Power, through these programs, if approved, to be able to leverage those for exactly as you said, Commissioner. For the benefits of the state, for the benefits of Georgia Power customers, to also incent cleaner resources to be installed than otherwise would if just providing the rates for those host customers.

VICE-CHAIRMAN ECHOLS: So would that be -- would that be batteries at that data center, instead of, say, a diesel gen set, or a combination of the two?

MR. EVANS: Absolutely. Potentially both. All are available. We will recognize the appropriate capacity value that the system can see from those and work with the customer on what those solutions are, provided that they fall under our requirements; right?

Having a firm fuel supply, make sure that we can rely on those when we need them; provided that they're certified and permitted for nonemergency use so that they can run to prevent the lights from going out, not just when there is an outage, things like that.

VICE-CHAIRMAN ECHOLS: And do any of those data centers, have they expressed an interest in doing some solar there -- 5, 10, 15 megawatts of solar, maybe more -- at those sites and then tying that into the system?

MR. EVANS: I'm not positive about that just due to the land restriction that they might have. I know that there's been some interest. I just don't know how far those talks have went.

VICE-CHAIRMAN ECHOLS: Are you familiar with the rule that you-all have that would keep a company from being able to go behind the meter on solar if, say, the array is across a public road and how that would prohibit them from doing that?

Are you familiar with that rule?

MR. EVANS: Somewhat. Not an expert in that, by any means.

VICE-CHAIRMAN ECHOLS: Do you think that we're in an extraordinary time when maybe we should relax a rule like that as we try to get ready for this, you know, unbelievable amount of power that we have?

Is that something that you-all might look at?

MR. EVANS: Well, for these types of programs and these customers, right, they're looking for that resiliency. So they'll be installing backup

batteries, backup generators that can whenever that outage occurs, whether it be at night or in a cold January morning.

So solar is absolutely -- and renewables is absolutely something they're interested in. But that serves a different purpose than the resiliency backup that we're looking for.

VICE-CHAIRMAN ECHOLS: Thank you.

CHAIRMAN SHAW: Mr. Thomas?

MR. THOMAS: Yes.

CHAIRMAN SHAW: I was just trying to get an idea on how -- how much longer on your cross because -- not rushing you, but just trying to plan for lunch.

MR. THOMAS: Just due to the nature of all the --

CHAIRMAN SHAW: Yeah. Well --

MR. THOMAS: -- witnesses being on one panel, I still have a -- a good amount.

CHAIRMAN SHAW: Just go ahead and make this one your last one before we break for lunch.

MR. THOMAS: Yes, sir.

BY MR. THOMAS:

Q Mr. Bush, just to -- to follow up to my question, I heard you give some reasons that the company

believes company ownership is beneficial. I didn't really hear an answer on cost-effectiveness.

So to follow up, I just wanted to know: Does the company plan to benchmark its self-built proposals against anything to determine the rate impact?

A (Witness Bush) I don't think we have a plan right now to benchmark. It's really important when you deploy a project is you understand that every project has its very unique characteristics. Sites are different, transmission availability is different. What you may have to do from a geotech perspective is different.

So what we do to ensure we're cost-effective is we go to the market and we engage suppliers to compete against one another. So, for example, for a battery deployment, we sent out an RFP this past year to different battery suppliers to see who will provide us the structure of the battery, the level of firmness that we need, the type of battery we want, and meet all of our technical requirements at the best value to our customers.

So we consistently will do that both to our -- an EPC agreement, as well as an equipment agreement. So we feel like we get the best value for our customers by allowing them to compete in that matter for these type projects.

Q So you're saying that there's going to be an

RFP in the -- for the self-built you're proposing?

A (Witness Bush) We -- we've already gone -- issued inquiry packages to different battery suppliers with our technical requirements and we're evaluating them even as we speak.

A (Witness Grubb) That's for the development of our company-owned resources.

A (Witness Bush) That's right.

A (Witness Grubb) That's the way that Mr. Bush develops it and reaches out to different vendors. Very similar to how we do in hydro modernization --

Q Okay. But there is not a competitive RFP?

I'm sorry that got confused in there.

A (Witness Grubb) No, no. You're right.

So I would say, Commissioners, again, the reason we're deploying these company-owned battery energy systems is because we can get them online before the year of need. And we can do that. There is not enough time to do an RFP.

But we have the 500 megawatt BESS RFP that's coming up. We've got the All Source RFP that's coming up. There's a lot of indications from that RFI that there's a lot of people interested in building batteries. We'd expect that.

That capacity need in that RFP is going to be in the thousands of megawatts. So there's a lot of

opportunities for the market to bid storage in the next few years for the company. Again, the reason we are deploying company-owned resources right now is for that need for speed to be able to get them online to serve these needs.

So, Mr. Thomas, what Mr. Bush was talking about is as he's developing that resource, he'll do RFPs to vendors and developers to put the project together.

Q But -- but isn't it true that since there is no competitive RFP, the Commission won't be able to gauge how cost-effective the projects are without some kind of benchmark, say the company's generation technology data book or generics?

Shouldn't there be something to benchmark it against?

A (Witness Grubb) Yeah. So -- so what we've done, we've provided the economic analysis in this filing comparing Robins and Moody's and the 200 megawatt plus solar to the PPAs and the Yates CTs. And so we have done that.

I think the other point would be that we -- we develop it at cost. And so whether we're bidding into an RFP or not, the company's cost is what it is. And so there's that economic analysis.

And then, again, the costs that we've estimated are in that analysis included in the statement that downward pressure on rates is expected. So we've captured that

there, as well.

Q So I'm a little confused. I thought I heard Mr. Bush say there's no plans for any kind of benchmark and then I feel like I hear you saying there possibly is. So --

A (Witness Grubb) I was just --

Q -- just help me --

A (Witness Grubb) I'm sorry. I was just speaking to there's lots of RFPs coming that batteries can bid into.

Q But -- but the company has no plans to benchmark the self-builts in order to help the Commission determine if they are cost-effective?

A (Witness Grubb) We've -- we've benchmarked them against the other resources in this filing. We need all those resources. And then, again, knowing that it's cost-effective is the way we've evaluated it. And then also the statement that we've looked at these resources compared to the revenues is downward pressure on rates.

Q Okay. But --

A (Witness Grubb) So that was the economics.

Q Cost-effective in -- relative to how the market could provide this. You're not planning on doing some kind of benchmark that would help replace what the competitive RFP provides?

A (Witness Grubb) Not now. I mean, every RFP is different. And so we'll be getting bids in those RFPs

sometime this year. And so we'll know more then.

But it doesn't change the fact, again, that we need to -- we have to deploy these resources at this time to have them online for the winter needs of '25, '26 and '27.

Q That would prevent you from having them benchmarked against something?

A (Witness Grubb) We definitely would not want to stop moving forward with them.

Q I understand that it could prevent a competitive RFP, but I don't understand how it could prevent benchmarking them.

A (Witness Grubb) So we would have to figure out what to benchmark it against and -- and would people be willing to give us their costing information. But it's something we could --

Q Is that something you're willing to explore?

A (Witness Grubb) We'll -- we'll -- we'll take it under consideration.

COMMISSONER McDONALD: Mr. Grubbs?

MR. GRUBB: Yes, sir.

COMMISSONER McDONALD: You -- you talk about the bidding out for the battery itself. But for the construction side of it, why do you say that there's not time for an RFP to -- on the construction side?

MR. GRUBB: So, again, from -- from an -- so if

it's talking about an RFP to actually build the company's battery, I'll let Mr. Bush speak to that.

When I was talking about timing on an RFP was to run our -- the Commission's RFP to take bids and then certify those bids and then -- then construct it. We don't have time to do that.

But as far as, like, deploying it and having the RFP for the people who are going to build it for the company, I think we have.

MR. BUSH: That -- that's right, Commissioner. You know, part of our issue here is the near-term need for capacity.

And so if you go to a traditional RFP that Mr. Grubb's is talking about, it takes a long time to -- to engage the market to do an RFP for that. And then there's uncertainty in the market and who might win and who might not.

So what we've done, recognizing the need, is we have gone in and engaged battery suppliers and those entities who have experience building and constructing and designing those facilities. So we've done both of those things.

And our plan is to continue forward with them, engage them, and have them construct the projects for us to be able to meet this near-term need.

MR. GRUBB: So, Commissioner, you're right. We were talking about two different types of RFPs. There are RFPs for services versus RFPs for capacity resources.

So what I was speaking to not having time to do was an RFP for capacity resources for the market.

CHAIRMAN SHAW: All right. We are going to break for lunch. So if everyone could be back here at 1:35.

(A recess was held from 12:36 p.m. until 1:35 p.m.)

CHAIRMAN SHAW: Go ahead, Mr. Thomas.

CONTINUED CROSS-EXAMINATION

BY MR. THOMAS:

Q So I wanted to pick back up on some further questions around BESS and wanted to ask some questions around BESS components. And I want to see if you could explain where the company is presently in the EPC procurement process of the three BESS projects.

A (Witness Bush) Certainly. The company issued an inquiry to the market for both -- back to battery manufacturers last fall. We received some of those -- we received the responses in December, and we are right now reviewing those responses to see if they meet our technical specs and requirements that we need for deploying batteries.

Simultaneously, we issued to engineering

procurement and construction companies a package to do that work as well for us in conjunction. So we expect those back in the next couple of weeks, and we will continue to evaluate them, such that we will put all of that together for each of the projects.

And we are doing these simultaneously, to bring that back to you, Commission, for your review and approval here as soon as we can get that worked up.

Q Is it possible that a developer may have already contracted for BESS components, and as such, could a developer offer a PPP -- I'm sorry -- a PPA or build transfer agreement at a lower cost than a company-sourced project?

A (Witness Grubb) You mean from an outside developer?

Q Yes.

A (Witness Grubb) Well, so, we don't have time to do the RFP process, so there would be a few things that they would have to have in place. One would be, is it contracted, can they get transmission service, and can they get interconnection service. And there is no -- there is no opportunity to go through an RFP.

But if a developer has a project and they would be willing to reach out to the company for company ownership, then we would be open to talking with them.

Q The company issued an RFI for capacity resources that would have been available between '26 and '28, at the end of 2023. The responses from third-party developers from the RFI indicated that the developers could potentially provide capacity at cost well below the three battery projects the company is proposing to self-build.

Is that -- would you agree with that assessment?

A (Witness Grubb) I would not totally agree with that assessment. Plus, I would correct that the RFI was not just for the time period in this 2023 IRP update. It was also for the '29 through '31. And the majority of our prices didn't even get -- the majority of the respondents didn't provide pricing.

So, again, if -- if -- there is not time to do an RFP to get those projects' pricing set and to do transmission studies. And so the RFI was very beneficial in that it backed up what we thought going into this case, there weren't a lot of existing resources available in this IRP update time frame.

It also gave us a lot of good information about the All Source RFP in terms of the magnitude of bids out there. And so, the ones that indicated they could build it by the '25 and '26, what we do not know is do they have transmission, and we would have to do an RFP to get pricing. So there is not time to take those respondents and go

through an RFP.

The battery resources that we have identified here today at Robins, Moody's, and the ones that Mr. Bush are working on are the ones that can meet the need, because you have got to move forward with the development now.

Q We talked a little bit before lunch about Georgia Power requesting an additional sum for five years of a PPA with Mississippi Power, even though Georgia Power customers only need the power for the last three years of the PPA.

Would you agree with me that when setting an additional sum, the Commission shall consider lost revenues, if any, changed risks, and an equitable sharing of benefits between the utility and its retail customers?

A (Witness Grubb) Yes. Those are the reasons stated in the law for the additional sum. I would note, again, that while the company's capacity need or needing resources to serve load is in that '26, '27, '28 time frame, we had to get all five years to have those last three. And so that's why the additional sum is applied to the entire term.

Again, we are looking to sell in those first two years as much of those resources we have -- can and have already sold 500 megawatts of it.

Q Does Georgia Power have any lost revenue in

those first two years?

A (Witness Grubb) Well, I don't know that you have to hit all three of those requirements in the law. The -- you couldn't build fast enough, but that's usually what the lost revenues are tied to. But you have also got the shared savings and the difference in risk.

Q Right. But just answering that question, Georgia Power doesn't have any lost revenues in those two years; correct?

A (Witness Grubb) From that PPA?

Q Yes.

A (Witness Grubb) Not compared to having built something.

Q As an equitable sharing of benefits, what benefit are Georgia ratepayers getting in those two years? I know you have explained the next three years; but in those two years, what benefit are ratepayers getting?

A (Witness Grubb) So I would say there is two things. One is any time you have reserves or resources on the system, you have a higher level of reliability. So even though you don't have to add it from a reserve margin standpoint, you will have those resources.

But the real benefit is, had we not executed those PPAs for the first two years, we would not have had them for the last three years, and we would be 1,000 megawatts short,

meaning we have less opportunity to put downward pressure on rates.

Q So under your proposal, ratepayers are already going to pay an additional sum in years three, four, and five, and so now the company wants to charge ratepayers in years one and two for the benefit of years three through five, and then wants to charge them again for that same benefit in years three through five?

A (Witness Grubb) So consistent with the '22 IRP, we are requesting an additional sum, as allowed by law, for all five years; and those additional sums are included in the economics that we filed in the case, including those that show downward pressure on rates.

Q But would you agree that you are wanting to charge them in years one and two for the benefits in years three and four -- three, four, and five that you are charging them for in years three, four, and five?

A (Witness Grubb) So we are requesting it, but, again, you couldn't have years three, four, and five if you'd also get the PPAs for years one and two.

Q Well, I am having trouble seeing where the benefit to customers is in years one and two. I see how Mississippi Power is getting a benefit. They are getting paid five more years for an asset that you said that Mississippi Commission was going to shut down, and I see how

Georgia Power is getting a benefit. You are getting an additional sum on a PPA that allows an affiliate to avoid a stranded asset.

But what benefit is the ratepayer getting in those two years?

A (Witness Grubb) So the customers are getting the benefit of having those resources to serve 750 megawatts of load that we have updated in this case; and in the first two years, there is additional generation on the system that would not have been there otherwise. And also, we have the opportunity to sell those megawatts and get revenues from other wholesale entities. So the customers benefit for the entire term of the PPA.

Q But we are still not sure; right? I think it is a hearing request whether selling of that will make up for the additional sum for the first two years; is that correct? We are still waiting to figure that out?

A (Witness Grubb) Right. Again, the additional sum recovery, the additional sum is still valuable from the fact that you have got all five years of those resources. And when we identified resources in this case, the challenge was the load can build faster than generation. So there was extreme value in existing resources that already had transmission service and didn't have construction risk.

And that's what those 980 megawatts of PPAs gave

us. They are actually the ones that can serve that first winter need while we are still developing the other resources. So we couldn't have this plan in place without those two PPAs.

VICE CHAIRMAN ECHOLS: So the Mississippi units, are they in good shape from an O&M standpoint?

MR. GRUBB: Yes, they will be. I mean, Mississippi, they are wanting that PPA to be -- I mean, it is in the pool; right? So they understand that having those units available in the pool is important to the entire pool.

VICE CHAIRMAN ECHOLS: Well, I take that it's a state of emergency today, I think. Are those units running today?

MR. GRUBB: I think we have got everything committed today, Commissioner, today and tomorrow. So again, some of those units would have been retired at the end of '23, had we not done this PPA.

COMMISSIONER PRIDEMORE: Did Mississippi Power retire those units?

MR. GRUBB: They did not, because of the PPA.

COMMISSIONER PRIDEMORE: But are they on the verge of retirement, as you say?

MR. GRUBB: That would be Mississippi's decision, but they will most likely extend those

through the term of the PPA. But that -- again, we are not tied to any specific unit with Mississippi. It is just 750 megawatts. So that will be up to Mississippi Power to make sure that they have got what they need for their customers and being able to support the PPA.

So I would believe they would extend them for a few more years. But at the end of the day, that's Mississippi's decision. But we have got the right to those 750 megawatts in the pool that would not have been there otherwise.

COMMISSIONER MCDONALD: Doesn't Mississippi have a need for capacity down the road?

MR. GRUBB: Not for a long time, Commissioner. And that's -- that was the point. And that's a great question. So when we talk about temporary surpluses and minuses, when Mississippi, they -- I believe they lost some wholesale customers, I think is one of their changes. So when their Commission looked at their resource plan -- and I can't remember if it was '21 or '22 IRP -- they were long for several years. And by quite a lot. And so the Commission asked them to reduce that -- those megawatts above target.

You know, at Georgia, we have been above, but we are usually above for three or four years. They

were above for a lot longer than that, as I understand it. So they were either going to retire them, per the Commission's directive, or sell them to another entity.

And so when our load forecast went up to the point that our need to add resources moved, those three years, we reached out to Mississippi and said, We need those in the pool. But we needed to make sure we had them through '28, and they needed to make sure that we were going to pay them through '28, so that's why it's a PPA.

BY MR. THOMAS:

Q Am I correct that the maximum discharge capacity of the Moody and Robins BESS sites is limited to the maximum output of the solar facilities that are already installed?

A (Witness Grubb) So, again, so you are asking about the capability of the batteries themselves?

Q Right.

A (Witness Grubb) Yes. So I will let Mr. Bush clarify, but, yes, they are -- the reason we went to those sites for the storage was to use the point of interconnection and the transmission services there for the solar. And so that's -- that's the limiting range.

But, Mr. Bush, do you want to add anything to it?

A (Witness Bush) No, that's -- that's correct. The output for -- the maximum output for the battery is the same as the nameplate output of the solar at each of those facilities.

Q So, for example, if BESS was charged and the sun was shining at Moody, the company could only export 49 megawatts of capacity; is that right?

A (Witness Bush) That's correct. The -- the point of interconnect at Moody is a 49-megawatt available transmission capability. And if solar is generating its full capacity, then there would be no opportunity for battery to discharge at that point.

Q Could the company export from battery and solar at the same time to the grid?

A (Witness Bush) Yes. The company can simultaneously export battery and solar. Again, it would -- to the extent that it can handle 49 megawatts.

A (Witness Grubb) And also, Commissioners, that 49 megawatts is a specific transmission case that we study. So there could be some other hours where you get a little bit more. But Mr. Bush is correct.

What we have done is, because you have to build transmission projects for almost any new generation on the system right now, when we looked at the need to move and get resources on-line in three years, we looked for transmission

areas where you didn't have to build projects to allow delivery on the rest of the system. So that's why we went to Robins and Moody.

Q Are there opportunities the company is now exploring for the near-term capacity need?

A (Witness Grubb) I am sorry. Could you repeat the question?

Q Well, I know that the company is no longer negotiating, right, for an additional ownership interest in an existing asset that I can't mention.

A (Witness Grubb) Right.

Q How is the company planning to fill the near-term needs that would have been satisfied by that acquisition?

A (Witness Grubb) Yes. So part of that is additional battery energies solutions for BESS. The other part would be the demand response. I mean, the demand -- distributed energy resource programs that Mr. Evans has spoken to. So between the two of those is where we would focus our efforts there.

Q Are you issuing an RFP for 500 megawatts of BESS this year?

A (Witness Grubb) We are. We are. And I think that's targeted to have those on-line I think by the end of -- it still has got to be figured out, but I think it

would be on-line by the end of '28.

Q Okay. So when would you issue -- do know when you would issue?

A (Witness Grubb) It will be sometime this year. I don't know exactly what date. We have got all the other RFPs we're working through, too.

Q Do you have an All Source RFP planned for the resources beginning in 2029 through 2031?

A (Witness Grubb) Right. So per the 2022 IRP order, that RFP is seeking resources to come on-line by the end of '28, '29, or '30.

Q Could --

VICE CHAIRMAN ECHOLS: Let me ask you about this demand response that you just mentioned, this program. Is this the smart thermostat Check TEMP program?

MR. EVANS: So I think what Mr. Grubb was referring to was the new DER programs with the co-location or the customer-owned programs that we have proposed in this case.

VICE CHAIRMAN ECHOLS: This smart thermostat program, you are planning on doubling the size, though, of that; right?

MR. EVANS: That's correct. We have proposed to double it from 25,000 to 50,000 customers.

VICE CHAIRMAN ECHOLS: And those events, when you call on those customers, that produces -- it gives us about 32 megawatts of demand response; is that right?

MR. EVANS: So I think it's a little bit smaller than that. From a resource planning standpoint, I think that might be right for what is enrolled. But from what is valued on the plan, it is a little bit smaller than that.

But to Mr. Grubb's point, any of the programs we have proposed, both the increase for the residential program, new enrollment in their curtailable load program, or the DER programs can all go to fill that capacity need that Mr. Grubb spoke to.

VICE CHAIRMAN ECHOLS: If you created a similar program with EV owners where they opt in and they know an event is coming, would it be safe to say that it would operate similar to this program, given that they are on the same type of circuit in a home where you could curtail those EV chargers for 15 minutes, like -- like they do in Colorado with Rolling Energy Resource? Is it safe to say that it would operate like that program?

MR. EVANS: There would be a lot of

similarities there. I think that's something that we are actively looking at, as Mr. Grubb spoke to earlier. EVs do introduce some additional complications, because now we are competing as a transportation resource with those customers; right? So we would have to balance those needs, and that might impact response time. But absolutely, there can be some value there, and that's something we are looking at.

VICE CHAIRMAN ECHOLS: Because a lot of people, they know what they will be doing at four o'clock tomorrow. Not everybody, but a lot of people do; right?

MR. EVANS: Yes.

VICE CHAIRMAN ECHOLS: Okay. Thanks.

BY MR. THOMAS:

Q Going back to the All Source RFP planned. Could the company adjust the All Source RFP such that bidders could offer capacity earlier than '29 if the Commission approved that?

A (Witness Grubb) So we could discuss that with staff. I know that is going on right now. But what you can't do is assuming that that RFP is going to have bids that can come in earlier and meet that need. And so while we can consider that, that RFP is designed for resources to

be on-line by the end of '28, not by the end of '27. So we will need to continue to look at resources to make sure we have them on-line by the end of '27.

Q Could the company issue an RFP for existing capacity or ESS immediately?

A (Witness Grubb) So there is -- there is not any existing resources available in the years of this IRP update that we are aware of. So we are going to move forward with the 2022 IRPs. But for these need years, these resources we have identified are the resources that can meet these needs.

An RFP, when you take a year -- two years to do the RFP, and even if you expedite it, you can only gain a little bit of time. But then you have also -- if you don't have existing resources -- and you have to have time for construction, which is at least three years, and you have got to take in transmission. So that's why we have not done it.

So to be clear, the company is absolutely supportive of the RFP process. We have done over 20 RFPs since 2006, and we have got seven coming out of the 2022 IRP that we will be doing. That's 27 RFPs since 2006. So we absolutely support the Commission's RFP process when there is time to do it.

And so in this case, there was not time to do it. Remember that -- the year of adding resources moved up three

years, so it ate up all the time to do RFPs, even if they expedite them. So that's why we looked to the market first that was existing and then went with the resources we could deploy.

Q Had the company -- had the company started both RFPs in June of 2023 when the company first notified staff of the increased load growth, would that have allowed the self-build resources proposed by the company to compete against the market?

A (Witness Grubb) It would have, but what it would not have done is allowed enough time to get certification and then move forward with the project. So the RFPs are not able to meet the needs in this case.

Q All right. I would like to turn to page 38 of your testimony surrounding the Yates CT project. Would you confirm that the company's transmission projects for the Yates CTs are only expected to be completed by the winter of '28-'29, and so only about 600 megawatts would be available in the winters of '26-'27 and '27-'28?

A (Witness Grubb) Yes. So for planning purposes, that's correct. We have got 600 megawatts firm, but we expect there will be a lot of hours in the year where the full out-source of those -- all three of those units will be available. From a planning standpoint across the peak, it is limited until those transmission projects are completed.

Q But one of the reasons you are requesting approval of the Yates CTs is because the company thinks that they can construct the CT faster than a third-party developer; is that right?

A (Witness Grubb) So I would -- we are -- we are not self-building that; right? It is a company-owned proposal. But, yes, there is no other entity that can go through an RFP and then build that resource that quickly. And so we are -- we have identified Yates because of several reasons.

Number one, when you look at the need for resources through '28 and beyond, it is a mix of solar, storage, and dispatchable resources, like combustion turbines and combined cycles. And on an accelerated schedule, you could have those units in during this IRP update.

Yes, there are some transmission limitations for some of those megawatts in those specific peak cases. But we expect those units to run a lot outside of those hours for all three of those units. And so what we have done is we have identified the need to build CTs as part of our resource mix, and so that's what we moved forward there. And we went to a site that we know that could minimize some of the risk of an accelerated schedule.

Q You would agree, though, wouldn't you, that the

company has incurred delays in all types of generation resources in the past, in constructing all types of generation resources?

A (Witness Grubb) I would disagree that we have done it on all. We have had a lot of self-build storage, solar come in on time. And then I would also let Mr. Bush speak to this, the project that we are looking at at Yates and the vendors that we are working with at Yates have had some recent experience that's much more relevant to prior Georgia Power deployments.

Q Oh, go ahead.

A (Witness Bush) Sure. Commissioners, the consortium that we actually have engaged for Plant Yates is a consortium that the company has used for past projects. We are talking about two large entities that have a global presence that have developed and deployed many projects of this type.

As a matter of fact, one of our other operating companies recently had one of their projects that the consortium built come on time and on budget just November of last year. And it was of a combined cycle nature, which is a more complex-type project. So we are very confident in the consortium's ability to do this.

We also have -- within the construct of the contract itself, we have provisions and protections for our

customers to ensure that they hit our time frame, that the megawatts that we expect will be there, that the efficiency of the resource will be there, all of those are guaranteed within the contract itself.

Q So consortium and protections for customers sounds familiar from other projects. But although you can point to projects that maybe have not been delayed, would you say that there has been a history of incurring delays in all different types of generation?

A (Witness Grubb) Across -- so first off, I am assuming you are talking about the most recent ones. Do you have any specific ones? Because if -- we have got a history of units that we have built, so...

Q So I heard you mention a couple. You know, it seemed like you were pointing mostly to battery storage that you had a history of on time?

A (Witness Grubb) So our military solar deployments that the company has built have been on time and under budget.

Q Okay.

A (Witness Grubb) And I would say Vogtle is the one most people are going to think about; but when we are talking about building CTs with a consortium, that's completely different than --

Q Right.

A -- restarting the nuclear industry --

Q Even Mossy Branch's --

MR. HEWITSON: Can we let him finish, please.

MR. THOMAS: Sure.

A So from a Vogtle standpoint, I think comparing Vogtle and everything this Commissioners is aware of, that we have done that, to building combustion turbines is not an accurate representation.

BY MR. THOMAS:

Q And I am not trying to make that comparison. I am just saying that the company has come in here times before and said that customers are protected and that they are always confident in their schedules. I know Mossy Branch is behind schedule, six months, I believe. And I know you gave a lot of excuses for -- or explanations for why. You know, was -- was McDonough built on time and on budget?

A (Witness Grubb) So McDonough gets a little more complicated because every one of those schedule changes was based on discussions with the Commission. I think there were some changes to those schedules based on impacts to rates. But I would say that McDonough has absolutely been critical and beneficial to customers.

I mean, it is one of the most efficient combined cycles we have on the system. It runs 85, 90, 95 percent

capacity factors all year. It is crucial to serving the loads in Metro Atlanta. And I would also remind everybody the first two McDonough units were responses to an RFP; that the RFP, nobody from the market bid into it. And so the company has experience of building generation when it is crucial and has challenging times. The company has done that.

Q So, yes, the company always has explanations for why they are behind schedule and over budget. But there are definitely examples from a variety of types of construction where that happens; right?

A (Witness Grubb) There are, but, again, that doesn't lead us directly to say that we can't build these CTs based on the most recent experience that we have on the system.

A (Witness Bush) Yes. I would just want to reiterate, Commissioners, that building a combustion turbine is very, very different than building a nuclear facility. And the experience that we have with the consortium, the contracts are very strong, they were premised off of what we did for the development of the combined cycle project. And that project with these two entities, it actually was built on time and under budget through a worldwide pandemic.

So we are very confident that following that same construct that we will be able to develop the Yates projects

and meet both the budget and the in-service requirements.

Q And that is good to hear, but that's not an example of Georgia Power bringing something on time or on budget; right?

A (Witness Bush) It is not, but, again, I would say --

Q Thanks.

A (Witness Bush) -- that we have built -- when we built the Robins, when we built Moody, when we built Benning, when we built Marine Corps Logistics Base, all of those projects were built on time and under budget.

Q Okay. I just thought you were heavily relying on an example and wanted to make sure it is clear that that was not a Georgia Power project; right?

A (Witness Bush) It isn't, but it is a complex project that is much more similar to a Yates combustion turbine than a Moody or a Robins project.

And that's why I bring it up, Commissioners. It actually is much more complex to build a combined cycle than it is to build a simple-cycle resource. So that's why I keep introducing that as information for the Commission to understand, that we -- that the confidence in our ability to build a simple-cycle CT is very high.

A (Witness Grubb) And the consortium that we are using is the consortium that built the unit in Alabama that

Mr. Bush is referring to.

A (Witness Bush) That's right.

A (Witness Grubb) Same builders.

Q So turning to carbon taxes and the fuel price assumptions, can you confirm that the company's economic analysis utilized the 2022 forecast data, and the company's mixed study used the 2023 data; is that right?

A (Witness Grubb) So help me -- so you are asking about both the resource mix study and the economic analysis that we filed?

Q That's right.

A (Witness Grubb) Okay. So you are asking vintages of what is used in each?

Q Right. I believe in -- the economic analysis is 2022 forecast data, and the mix study is 2023 data; is that correct?

A (Witness Grubb) No.

Q No?

A (Witness Grubb) So the only thing in the economic analysis that's not fully up to date with the '23 IRP update, the resource mix study has everything up to date, is the energy values. We used last year's energy values vintages versus this year's. But again, not a large change there and doesn't change the impact.

So everything else in the economic analysis and

the resource mix is with the information coincident with our latest updates, except for that one factor.

Q And that's helpful. And so can you just explain for us why you used those energy values?

A (Witness Grubb) Sure. That's what was available at the time we were evaluating them.

So, Commissioners, when the capacity need year moved in June and we said we've got to have resources on by '25, '26, and '27, we started looking at all those options. And as we were going through those options, we were studying and screening transmission, and we were doing the economic analysis through July, August. Those were the energy values we had. To help us decide on which ones were the resources that were most beneficial for customers.

When we did the resource mix study, we did that after we had our latest data. So it was based on what we had available at the time to assist us in identifying what to bring forward to the Commission.

Q All right. And moving to the CO2 forecast assumptions, can you explain what the purpose of the carbon tax modeling is in this IRP update?

A (Witness Grubb) Yes. So, Commissioners, it is the exact same thing we have done in all the prior IRPs since the early 2000s. So as y'all are aware, we have planning scenarios that look at a range of carbon pressures.

And so we used that same -- we used a range of carbon pressures in the economic analysis and the resource mix plan, just like we have in prior IRPs, on the same models, and unit retirement studies.

Q And I noticed that the company's economic analysis used CO2 tax starting in 2025 where the mix used 2030. And I wanted to see if you could just explain why you thought '25 was a reasonable assumption date.

A (Witness Grubb) So I would have to confirm those dates; but each year when we do the planning scenarios, the carbon tax start year is usually moved out two or three years based on what we have seen in the market. So we haven't adjusted that a lot over the last several IRPs, except to shift it out a few years.

So I would have to go back, Mr. Thomas, and look at when the tax year starts. Are you asking about the resource mix study?

Q Yes.

A (Witness Grubb) Okay.

Q Yes.

A (Witness Grubb) But again, it would be -- what we are looking at those scenarios is carbon pressures, and so you are looking a few years out so that you can have the model respond to those.

Q Thank you. And I would like to turn to the

Flex Capacity framework. Starting on page 51 --

A (Witness Grubb) Is this in testimony and not the main filing?

Q Yes, I believe this is in --

A (Witness Grubb) Yeah. I don't think there is a 51 in the main, so I think you are right.

COMMISSIONER PRIDEMORE: While you look that up, Mr. Thomas, let me ask the panel a question.

MR. THOMAS: Sure.

COMMISSIONER PRIDEMORE: To piggyback on one of Mr. Thomas's questions about the procurement of the megawatts from Mississippi Power.

So we are at the stage now within questioning what we are talking about. Carbon, the price of carbon. Does the contract with Mississippi Power dictate the type of power that's being purchased from them?

MR. GRUBB: It does not. So it is through '28, and it is for 750 megawatts from their fleet.

COMMISSIONER PRIDEMORE: So if the Mississippi Commission decides to institute an RPS and put a limit on the amount of carbon that they could emit, they could find themselves in a capacity shortage; right?

MR. GRUBB: I don't know that Mississippi

would. I can't remember the rest of their plans. But I think one thing it's important to remember is we are talking a five-year contract, not 5 or 10 or 15. But I think what we would have to do is Mississippi would have to make that decision based on their customers. But I don't know, you know, the timing of when that would happen. But they could; but then again, Mississippi would have to make a decision on what they are going to back up the PPA with.

COMMISSIONER PRIDEMORE: But we are not purchasing carbon neutral capacity. We are just purchasing capacity, regardless of the carbon?

MR. GRUBB: Right. So the Southern Company fleet is going to dispatch, just like it dispatches, regardless of the PPA. So if the Mississippi units are economic to dispatch, they will dispatch, and everything will happen through the pool.

But when we look at where each operating company is in their reserves, 750 megawatts is showing on Georgia Power's reserves versus Mississippi's. But everything else works just the same.

COMMISSIONER PRIDEMORE: But we are not talking about economic dispatch in this sense. We are

talking about the carbon -- I hate to use the word "footprint," but the carbon likeness of their fleet. So if they decide -- you know, Mississippi has factors that we don't have. They have two electric utilities. They have an RTO in that state. You know, if there are factors that are outside of the same level of control that I have or that these -- you know, Commissioners in this Commission has over Georgia Power, how can we be sure that we are not going to then just purchase Mississippi's dirty power?

MR. GRUBB: So a few things. One, Mississippi has an RTO in it, but, obviously, Mississippi Power is part of the Southern pool. But you are right, it is part of the state, just not Mississippi. I -- just clarifying. I know that's not what you meant. But, so, again --

COMMISSIONER PRIDEMORE: I know, but they have an RTO in their state and we don't.

MR. GRUBB: They do. They do. And so, again, if they have some sort of rule, Mississippi is going to have to make a decision on what to do with their units. Again, I think the risk is low, looking a few years out. But I think, more importantly, is those were resources that we could meet to meet these

needs. And so, there is not a lot of other options other than developing, which is tough to do, other than what we have identified.

So I can't speak to exactly what the Commission is going to do over there. But if, for some reason, they can't back that up, we would have to go find other sources. But we think that risk is really low.

COMMISSIONER PRIDEMORE: I mean, they have a brand new Commission with all -- three brand new -- they are a three-person commission with three new members. Okay.

Thank you. Go ahead, Mr. Thomas. Sorry for the interruption.

MR. THOMAS: Thank you.

VICE CHAIRMAN ECHOLS: Hey, just one more thing on that Mississippi grid. I know that we are wheeling some wind from Oklahoma; right? 250 megawatts into that Mississippi system. And we had had some interconnection issues, I think, with that.

Are we still counting on that 250, or are you still including that?

MR. GRUBB: Are you referring to the Blue Canyon?

VICE CHAIRMAN ECHOLS: Yes.

MR. GRUBB: Yes, it is still in our plans. And, again, the Mississippi PPA doesn't physically change anything that's gone on in the Southern pool. The only thing it does is make sure that those 750 megawatts stay in that pool through 2028. But physically, nothing else is changing. Dispatch isn't changing, any of those types of things. But we do still reflect Blue Canyon, Commissioners.

BY MR. THOMAS:

Q All right. Turning to page 51 of your testimony, line 24, under the Flex Capacity framework, the company is requesting pre-approval of costs that may or may not be incurred by the company for developing or procuring additional capacity; is that correct?

A (Witness Grubb) That's right.

Q And what protections does the Flex Capacity framework provide to customers if the cost of development are excessive, given that they aren't vetted through a competitive process?

A (Witness Grubb) So any of those costs have to come before this Commission. And so the ultimate authority and impact to customers is this Commission. And, again, this would -- this would be for resources above what we have asked for in this case, if certain criteria are met. But, again, the ultimate authority is the Commission.

Q That's correct. But those prices will not have been vetted against the competitive process for this Commission to review to help them determine if they are cost effective; is that correct?

A (Witness Grubb) Correct. Because there is not enough time to solicit the market for resources to be on-line by that time.

Q Okay. So what processes are in place to help the Commission determine whether they were cost effective?

A (Witness Grubb) So we file the contracts. We file everything with the Commission to give their purview on those. We have provided the economic analysis for the resources in this plan. At the end of the day, when we bring those to the Commission for certification, they have the ultimate say.

So, again, the Flex Capacity would be for anything above what is in this case. And so it would be based on the development at that time.

Q And I am not debating on you -- with you whether the Commission has the authority whether or not to approve those. I think we all agree on that. My question goes more to what tools do they use to determine if it is effective if, you know, there is not a benchmark and there is not a competitive process?

A (Witness Grubb) So again, they will know all of

the costs and what the costs are developed for, just like anything the company would bid in to an RFP. It is the same development process, so they have all the information to respond to there.

You are right, they wouldn't have any market response to compare it to, but that's because the market can't respond and build resources by that time, that we are aware of.

Q Is there some kind of benchmark you can use in lieu of market response?

A (Witness Grubb) Well, so, I mean, Mr. Bush can speak to this some, but, I mean, his job is develop resources. And so we have got information across the system. We have got industry information that lets us know where we are in terms of the neighborhood of those costs. But every site is specific. But I think there are other sources that we look at.

A (Witness Bush) That's right. I just want to clarify a little bit for the Commission. There is an RFP process that the company normally goes through, and it is a longer process that allows a lot of folks to participate in. But because of the time frame in this -- in these proceedings and the need for capacity in the near term, the company couldn't -- doesn't have time to go through that process.

But as the developer for the company, when we develop a project, we call it for the -- as a company-owned proposal, we do, in fact, go to the market. As I mentioned earlier, we send inquiries out to different manufacturers of batteries, and they respond. And they have a price; and they have terms; and they have conditions, all of which we evaluate. And we pick the best value for our customers.

So while that -- and by the way, if there was a company RFP, that's the process that we go by. We would do that, take that information, and then submit it into the company RFP to compete.

So we do have a process whereby we look to get the best value for our customers and go to the market and effectively have these vendors compete with one another -- with one another to ensure that we get the best value for the customers.

COMMISSIONER MCDONALD: Mr. Bush, would you be the one managing this?

MR. BUSH: Yes, sir. That's --

COMMISSIONER MCDONALD: You would be the go-to?

MR. BUSH: Yes, sir. I am responsible for ensuring that when we have that process, we get the best value for our customers.

BY MR. THOMAS:

Q And I think you pointed to the issue that I am trying to raise, is that the bid -- the package you put together, yes, you have an RFP with subcontractors, but the element that's missing is your proposal being vetted in a competitive process against those of others. So it is fundamentally different. Would you not agree with that?

A (Witness Grubb) So what I would say is that there is -- again, there is not enough time to do an RFP, and the Commission's rules allow for these unprecedented types of events where there is not enough time to do an RFP. So that's what we are using here.

Again, 27 RFPs between what we have done in the past and what we will be doing coming out of 2022 the IRP, so we absolutely support the RFP process when we can do it.

So, yes, we won't have market bids to compare it to, but the market can't respond in this time frame. And so it comes down to looking at the costs, reviewing the costs, we have evaluated them, and we have included those costs in the analysis, compared to the revenues, that supports our statement that this filing puts downward pressure on rates.

Q In this IRP update filing, the company has proposed two DER programs, DER co-location and DER customer-owned, programs which build upon previously-approved DER programs from the '22 IRP.

Were these two new programs modeled after a

utility in another state?

A (Witness Evans) No, not necessarily. Of course, we monitor that and look at what other programs are doing; but these programs were modeled mostly off of feedback, direct feedback, from customers as we solicited, the current programs that we have authorized and tariffs approved for, and realizing what elements the current programs worked or didn't work for customers, and then hearing what their needs were going forward and what types of assets they were looking for. Things like that.

Q And regarding the DER co-location and customer-owned programs, the company states in its testimony on page 44 that the -- I believe lines 15 and 16 -- that the payments to participating customers will be based on 75 percent of system value.

Can you describe in further detail how exactly the calculation of the net present value of the system for these programs will be done?

A (Witness Evans) Sure. It is a -- this is a shared savings model, not different from what we have in other programs, like our DSM programs. We are setting incentive levels. And shared savings models that are not uncommon to the utility industry.

What it does is it ensures two things. One, that all customers will benefit from these programs by system

value being realized at a certain level, but then being paid for at 75 percent of that. So say, for instance, that for a given customer, their resource was going to provide $100 worth of value to the system. Well, our customers would only pay for $75 of that. So that would immediately see benefit for all nonparticipating customers.

We also think that that level of an incentive or that level of a payment or a credit, depending on the program you are looking at, also provides a significant opportunity for participating customers to receive a benefit for assets that they were already looking to install for resiliency purposes.

So we really think it is a win-win, both for participating customers and for nonparticipating customers.

Q Does the company anticipate any situation in which nonparticipating customers would be responsible for paying for the cost of this program, you know, where a customer fails to make a payment or something of that nature?

A (Witness Evans) No. Unlike the current program where those payments are done over a contract period, for the -- for the co-location, not the customer-owned, because the customer-owned, there is no -- there is no payment from the customer; right? They are buying their own asset and participating in our program, which the company can dispatch

it for system benefits.

But for the co-location program, unlike our current DER programs, those aren't going to be paid for over a period of time over the contract. Those are going to be paid for up front.

Q Thank you. The company's most recent ELCC study assigned a capacity value for new standalone utility scale solar at 5 percent of the facility size for the winter season, while the utility scale projects that are paired with energy storage receive 100 percent of the capacity value of their storage facility. Is that correct?

A (Witness Grubb) Yes, that's correct.

Q Okay. And Georgia Power recently released its utility scale solar RFP, and it's targeting approximately 3 gigawatts of solar and solar-plus storage with in-service dates of no later than 2028 and as early as 2026.

As part of the IRP update in terms of supply-side resources, your only -- you are only assuming that solar facilities will be selected in the CARES RFP; right?

A (Witness Grubb) So you are asking what we have incorporated into our planning? Yes. So we would have -- we would reflect the megawatts that are being sought in CARES. We don't have project specifics, obviously. We don't do that until we get the actual projects.

Q So why haven't you forecasted any solar-plus

storage projects to win the CARES RFP, which would contribute 100 percent of their facility size as capacity to the system?

A (Witness Grubb) So I am not familiar with all the details in the utility scale RFP, and I am not aware that the storage that is bid in with those. In the past, it has always been the intermittency of the solar, not a storage resource for capacity purposes.

So that would be the reason. It is not a -- it is not a capacity solicitation. It is an energy solicitation. But I am not aware of that we have -- we have structured that RFP where the batteries would be similar to the batteries we are talking about here.

Q Well, but haven't -- in the 2022 and 2021 REDI RFP and the 2022-2023 utility scale, hasn't there been solar-plus storage bids so that you -- you can anticipate some solar-plus storage?

A (Witness Grubb) Yes. So we don't project what is going to win, because, again, those RFPs are for energy savings, not capacity. And so, again, the solar-plus storage -- well, I would rephrase it. Storage -- solar-plus storage, what we are talking about is storage plus solar. I know I am finding a little nuance.

But what we are looking at in this IRP update is storage to meet capacity needs that could be charged with

solar. Those RFPs for CARES are for solar megawatt hours to give us the energy benefits, the RECs for subscriptions, and then storage can be built in to handle some of the intermittency. It is a different use case.

Q And am I correct that on Georgia Power's transmission system congestion often occurs during periods of peak need?

A (Witness Grubb) I wouldn't say we have congestion on every period of peak needs. We study our transmission project -- our planning to make sure that we don't have congestion. So when we identify -- we identify projects to allow delivery of resources to avoid congestion. So I wouldn't agree that we have congestion on every peak period on our system.

Q Yeah, that's not what I asked. Let me try to make that more clear.

A (Witness Grubb) Okay.

Q I said -- I don't think I said "on all periods of peak." I said that "congestion often occurs during periods of peak"; right? Isn't that the time --

A (Witness Grubb) So it depends on what you mean by "congestion."

Q Well, you are not going to experience that outside of peak needs, are you?

A (Witness Grubb) Not usually.

So what we do, Commission, is we -- just like we have done for the last several years in IRPs, we study transmission from a NERC transmission planning reliability standards. So that's what we are evaluating across peak periods, to make sure that we can support firm and future firm resources and confirmed loads. And so that's what we have studied.

And so if there is some restrictions on the peaks, we identify projects to address those concerns and build those, and that's what we do in our transmission planning process.

VICE CHAIRMAN ECHOLS: I have asked you about congested circuits before, you may remember.

MR. GRUBB: Are you talking about transmission or distribution?

VICE CHAIRMAN ECHOLS: Distribution. So we have talked about congested circuits in Metro, and possibly, you know, sending a price signal to -- you know, to customers along that circuit, that those that would add solar to their home would receive a higher amount, because we have got congestion there.

Do you remember me asking you about this maybe three years ago and six years ago --

MR. GRUBB: Yes.

VICE CHAIRMAN ECHOLS: -- and nine years ago?

MR. GRUBB: Nine, yes. So -- I'm sorry, go ahead.

VICE CHAIRMAN ECHOLS: And I am asking you about it again, because it seems like now, more than ever, we need some creative solutions; and I just wonder if that's crossed your mind, the conversations we have had through the years?

MR. GRUBB: Yes, so a few things. One, a lot of times when people talk about congestion, they are thinking of other markets where, instead of doing transmission planning like we do, they send price signals so people will respond with resources to handle that. That's not what we are talking about.

What you are talking about is are -- is there some locational value that's more of a long-term --

VICE CHAIRMAN ECHOLS: Yes, locational, marginal --

MR. GRUBB: Maybe not a day to day. We did do a locational value study coming out of the last -- I am drawing a blank on which IRP we have done. But we did do one. And so I don't know where we are on applying that in any of the RFPs. But we have done one to look at kind of the bigger areas of the state. It was more transmission than it was distribution, but to say that there is a value of having things in

Metro versus not.

And so we did do a study. I think that was out of the '22 IRP, and we finished last year. But I am not sure where it is on the use in RFPs. So we have -- we have progressed some towards your issue there. Nine years later.

VICE CHAIRMAN ECHOLS: I am encouraged. Yeah, good. Thank you.

MR. GRUBB: I'm just a little rusty on the latest on that study. My apologies.

BY MR. THOMAS:

Q Has the company assessed how curtailment risk will limit the capacity contribution of proposed Plant Yates CTs; and if so, what did the company find?

A (Witness Grubb) So could you ask the question again?

Q Sure.

A (Witness Grubb) I just want to make sure I am thinking of the right aspects.

Q Have you assessed how curtailment risk will limit Plant Yates contribution to capacity or if it will?

A (Witness Grubb) So, Commissioners, we did study that. What we have done, again, is followed our traditional transmission planning process. So we looked at all of these resources, especially Yates. We look at where that resource

is and what projects are needed to allow it to have firm delivery.

So we did identify projects that are needed, especially with increased loads, to allow those resources to dispatch across the peaks. And so, there are other hours that aren't as constrained that you will be able to get different outputs on, but we did study it. We have identified it. We have asked for the approval of those projects.

We will update that study this month that shows actually the cost of those projects for Yates will be lower than what we included. But we identified the restrictions. We have captured it in our needs planning. We have captured it in the economics. And we have captured it in all of our other analysis in the filing.

Q Does the company believe that Mississippi Power and Santa Rosa PPAs will be deliverable capacity resources that are not at risk for curtailment during peak need?

A (Witness Grubb) Yes. So we identified and did those studies for Mississippi. Obviously, it is in the system, so there is no issue there. For Santa Rosa, we identified no projects that are going to be needed to allow that resource to serve from Florida into the Southern territory.

We did update Friday that we did the interface

study, which we did mention in the main filing, that we aren't sure that we will get ability to serve across the interface for the first two years. We won't know until a year out. So we will continue to look to sell those, but they will be available across the peak. So we do study that. That's what we study on transmission.

Q Has the company evaluated whether the transmission upgrades identified in the transmission screening analysis could be reduced, deferred, or eliminated with development of grid enhancing technologies, such as line ratings, topology, optimization, power flow control devices, and other solutions?

A (Witness Grubb) So what we did, Commissioners, is we looked at alternatives such as operating guidelines, redispatch, and then reconductering and rebuilding. And so what we have identified are projects that are typically associated with adding resources. And they are projects that are needed to allow the deliverability from Yates around the clock.

And so we have identified. We didn't look at every single alternative, because the timing was pretty tight. But we did look at redispatch, operating guidelines, and identified projects that are very similar -- very typical for needing to add resources. And they are wired solutions.

Q To what extent has the company revised or edited the quarterly load assumptions in the model provided -- and I am sorry; I am turning to load realization model now. But to what extent has the company revised or edited the quarterly load assumptions in the model provided by each large load customer? I think it's in Technical Appendix 7.

A (Witness Valle) Yes. So the load forecast is an annual process. So we completed one the early days of September of this year. We expect to complete another one by August. So it is an annual occurrence. Because of the large loads that were coming to our state, we felt that we needed to study and quantify the impacts to see if we needed to take any actions for it.

So we did that throughout 2023. We did one in January, another one in March, another one in June, July, and the final one for this request was done in August.

Q Okay. And to what extent did the company request load to ramp up at different rates than announced? So to push out when the need to meet the load, you know, to give them more time? Have you looked at that?

A (Witness Grubb) I am sorry. Can you -- are you asking about -- are you asking about each -- I am sorry. Are you asking about how we forecast particular customer ramp rates?

Q Right. So have you looked up -- or looked at any ways that you might be able to do that at a different rate than you have shown, to giving more time to meet capacity through something like an RFP?

A (Witness Valle) No. That's not the way the forecasting works. So first, you identify the load that you need to serve, and then you plan for the system to do so. So as the load was materializing, as new customers were coming to the state, we were quantifying that and reflecting it into the adjustment for large loads.

A (Witness Evans) And at that same time, whenever we are developing and working with customers on what their offers are, we are firming up to make sure that those load ramps are exactly what they need; right? To make sure that, one, we can reliably serve them, and, two, that we are incorporating the appropriate cost in what those offers are.

A (Witness Grubb) So, Commissioners, I think the other part of that question was, did we basically push the loads out until we could do an RFP. And the answer is, no. But we have never planned that way. Again, this is the one time we have come in with a load forecast update that doesn't really allow for an RFP timing.

And so, what we do is we do like we have always done. We take a solid good load forecast that's needed to serve the state, and we identify the capacity plan to serve

that load. And so that's what we have done here. If you push the load out and try to delay it, what you are doing, ultimately, is losing the opportunity to place more downward pressure on rates for all customers.

Q Thank you. And turning to Ratepayer Impact model, looking at page 49 of your testimony. You indicate that Customer Choice projects all pass the RIM test; is that correct?

A (Witness Evans) That's correct.

Q Okay. On page 49 of your testimony, on lines 16 to 21, you state that, each new economic development project has passed the financial and economic screening requirements, including the Ratepayer Impact Measure, RIM test. Georgia Power expects existing and new customers to recognize economic benefits from this energy usage growth which will help offset and balance the cost of investments needed to serve Georgia Power's growing energy needs.

Will customer rates increase as a result of Customer Choice investments?

A (Witness Grubb) Are you talking about all customers?

Q Right.

A (Witness Grubb) The answer would be no.

Q Okay.

A (Witness Grubb) As we have said here before,

the revenues from these loads exceed the cost of the resources to serve them.

Q However, the company's revenue requirements will increase, right, if the PPAs and self-build projects are approved?

A (Witness Grubb) So the revenue requirements will increase; but, again, the revenues from the loads that those resources are serving are greater than those revenue requirements.

Q And can you tell me how much of the new load is outside of Georgia Power's service territory?

A (Witness Grubb) I think Mr. Valle has that number. I would say, Commissioners, we don't usually -- we never look at inside/outside service territory in our load forecast or what we look to serve. We have always looked at the economics in the forecast. We have also planned to serve load.

And so he can give you the background, but I just want to let you all know that we plan to serve the growth in the state regardless of which territory it is in.

Do you have the statistics?

A (Witness Valle) Yes. So the loading inside of territory from the announcements is roughly a third of the total in the pipeline.

Q I am sorry, I had a hard time hearing you. Did

you say a third of it is outside the company's --

A (Witness Valle) A third is inside the company.

Q Oh, only a third is inside the company service territory? Okay.

A (Witness Grubb) I think, Commissioners, another thing that's important to think about inside and outside service territory is the Territorial Act is very beneficial to the state. And when you talk inside and outside service territory, you could be talking about the exact same industrial park.

And so we have always competed for Customer Choice jobs. The EMCs have always competed for Customer Choice jobs. And so we have always had a mix of inside and outside service territory in our load forecast for forever, for lack of a better term. The magnitude is just different here, but we have always had that.

Q And that's what I was going to ask: Have you ever seen it where two-thirds is outside the service territory?

A (Witness Grubb) I don't know that we have. Again, when we have a load forecast, back before these large external adjustments that we are doing, we would have an industrial forecast. It never really said what is in or outside the territory. But, again, any project that we win helps put downward pressure on rates.

VICE CHAIRMAN ECHOLS: I guess the benefit to it being outside, is the pollution is not in Georgia; right? It's in Mississippi; it's in other places.

MR. GRUBB: Yeah. From a resource standpoint, too. But what Mr. Thomas is asking about is actually service territories of us versus the EMCs. And so our load forecast is capturing customers we have won, projected customers, regardless of territory. So we -- there is a lot of outside service territory.

VICE CHAIRMAN ECHOLS: Yeah.

MR. GRUBB: But we always want to be able to support the state. It benefits our customers to compete. The other entities in the state compete, as well. So the Territorial Act has been in place since about two months before I was born, so it has been around for a while. And it helps with economic development, reliability, and rates.

And so we have always planned for a combination of both. The magnitude is different here, but the concept and the planning process is not any different.

BY MR. THOMAS:

Q And Georgia Power doesn't have an obligation to serve outside its territory; right?

A (Witness Grubb) We do not. We have the

obligation to serve inside, but we have the opportunity to compete outside. And it is beneficial. Again, I would say that, you know, you are not -- we serve all but four counties in the state, so when you are talking inside and outside service territory, our lines could actually be closer. So we don't have an obligation to serve, but, again, the more resources we have, the more load we can compete for, the more downward pressure on rates for all of our customers.

MR. THOMAS: That's all the questions I have.

COMMISSIONER MCDONALD: Thank you, sir.

Advanced Power Alliance?

MR. CARVER: Good afternoon.

MR. EVANS: Good afternoon.

MR. VALLE: Good afternoon.

MR. GRUBB: Good afternoon, Mr. Carver.

MR. BUSH: Good afternoon.

MR. CARVER: I am Brad Carver on behalf of the Advanced Power Alliance. Just as a reminder, Georgia Large Scale Solar Association merged with Advanced Power Alliance. And so we are -- now we represent the utility scale solar industry in Georgia, as we know. And enjoyed working with y'all in the previous IRP, and I just have a few questions for you today.

CROSS-EXAMINATION

BY MR. CARVER:

Q So we have talked a lot about the need for this new load; and, certainly, as we have said many times in here, Georgia being the number one state to do business and the economic development opportunities we are seeing across the state, there is concerns from the market about continuing to keep us in that position because of, frankly, perhaps a shortage or shortfall or having more demand for green renewable energy than is able to be procured by the market.

So -- and I will point to -- certainly, with our clean tech industry in Georgia, a lot of these companies are demanding 100 percent green energy. So I -- we do know now that the Clean Energy Buyers Association, 100 companies that are interested in the Georgia market, have intervened in this case.

And so I just want to ask the panel, you know, are we going to be able to continue to supply the demands of our C&I customers in this state, both new and existing?

A (Witness Grubb) Yes. So I think there is two aspects to that, Mr. Carver. One is the solar programs and the subscription programs that we have done in the past that you are very familiar with. We have got the CARES RFP that was approved in the '22 IRP that is 3,200 megawatts. And so, we are going to continue to move forward with solar.

The expansion plans that we show with the IRA that was discussed earlier shows an even more economic signal for solar. And so in the 2025 IRP, the company will bring forth what is our next step in renewable procurement. So from a renewable standpoint, I still see us moving forward there. And we have identified, in the '22 IRP, transmission projects that are needed. We are working on those transmission projects.

So in terms of continuing to procure solar, the signal is still strong to do that. In terms of this filing and looking at capacity resources from a fleet transition standpoint, this plan is consistent with what we have done in the '22 IRP.

So we have got it. We are looking at adding a lot of storage that helps from that standpoint. And we are going to continue to move forward in that fleet transition. So there is no 100 percent carbon-free energy dispatchable resource that we could deploy in the next three years to meet this. But the plan is consistent with our carbon approach in the continued fleet transition.

Q And your answer would remain the same even though the second REDI RFP procured zero megawatts due to the supply chain constraints, et cetera, the problems we have seen over the last couple years?

A (Witness Grubb) So those megawatts are rolled

over into CARES, and so we will continue to move forward with those. But you are right, there were a lot of drivers for that. But it was -- we will continue to move forward with solar procurements.

Q Let me turn you to page 21 of your testimony, lines 13 to 22, and you have -- you have discussed this a little bit about the time lengths. You state Georgia Power's RFP process typically takes two and-a-half years. You have a -- but right now, you have an open RFP, as we know. There is -- again, I am speaking on behalf of the association here, not any individual bidders. We have a lot of our members that are, of course, interested in your current RFPs, so I am not commenting on any individual bidders here.

But from an industry perspective, you have an open RFP right now. And from the 2022 IRP order, the order says that you have this procurement -- and, again, this is CARES one, and you are going to have a second CARES RFP on down the line. This one is currently open. It indicated that there is an opportunity for economic development reasons to be able to acquire -- acquire additional resources.

And so I guess my question to you is, you talk about the time length it takes for an RFP, but you have an RFP that's open right now. Could you not take advantage of the open RFP right now and roll more megawatts in for

economic development?

A (Witness Grubb) So for this filing, we are focused on capacity resources, and that RFP is not for capacity resources. So we cannot use CARES to meet the needs in this IRP update. But the economic development aspect of CARES is from the '22 IRP, noting that we could have more demand than there -- than CARES may procure and having the option to see if people want to continue to do that.

And so the '22 IRP allowed for an economic development part of CARES. But the reason that RFP isn't of any service to serve the need we have identified in this IRP update is it is not for capacity resources.

Q But it is open now, and if you had a need right now -- because, again, as was stated this fall, and as we started the RFP process -- again, I know we are talking IRP. This is a new IRP, this is capacity resources. But this fall you indicated, when the RFP docket was opened, that there was concern because of the REDI second RFP not procuring any megawatts.

I -- is there not additional demand out there from C&I customers existing today that cannot be supplied because that REDI RFP number two didn't procure any megawatts?

A (Witness Grubb) So I am not involved in the day to day of the CARES renewable RFPs, but my understanding is

we rolled those megawatts into CARES. And so we're procuring the last part of that CRSP part two that didn't come to fruition. We are rolling that in and going to the market for that again. So we are doing the additional megawatts that didn't get done.

So can you use that for more solar? I will leave that to the -- to CARES utility scale RFP to handle. This filing is about meeting the economic development needs from a capacity standpoint.

Q Okay. Your -- so there was a lot of discussion around your -- the Mossy Branch battery storage projects. That's a 80-megawatt battery. That's from the 2019 IRP, Staff Data Request JKA 5-5. The question from staff was, When will Mossy Branch be on-line. They asked, Was it going to be January 2027? The response was, It is really June 2024. So coming up here in June. But that testing would not be finished until January 2027.

Is that right? Is it that length of time to do the testing?

A (Witness Grubb) So I don't have that DR, but I will take you that you responded correctly there. I am not saying you didn't, but I don't have it in front of me. But, yes, so I will let Mr. Bush add in here. That was a -- that was an early demonstration project that the Commission gave us approval for to do learnings on storage.

And so, we will have it on-line, and then we will be testing different use cases. And it will be -- once we get through that, it will help meet capacity needs, from a planning standpoint. I mean, obviously, if it is dispatching on the system, we're testing it, it's serving load. But from a resource planning standpoint, we aren't counting on those megawatts.

Q Until testing is complete?

A (Witness Grubb) Until testing is complete.

Q Okay. I just was curious about the timeline. That just seemed like a lengthy period of time.

A (Witness Grubb) We are going to learn a lot.

Q Okay. And around, you know, the battery storage provisions -- and you had, obviously, a lot of cross-examination from staff around this. As you know, we have, obviously, procured utility scale solar resources through the competitive bid process. And, again, I -- your answer continues to go back to the length -- the length of time it takes to have an IE RFP initiated process and the length of time that takes to bring resources to bear in the market.

But I just want to -- I want to go back to that, because I want to point you to the Texas winter storm and everything that we have learned from that. You -- we did actually hear from, I guess, our public witnesses this

morning. In Texas, following the winter storm, they procured 3 gigawatts of battery storage, and they have done that over a two-year time period. And they did that through competitive bid procurement.

Now, assuming that is a deregulated market, we are a regulated market. I understand a significant difference there. But in that situation, Texas used a competitive bid procurement process and were able to bring on-line 2 gigawatts of battery storage.

Is there not a way we can speed up an RFP process, especially considering you have an RFP for 500 megawatts of battery storage that came out of the previous IRP that will be going to market at some point or the RFP will come to market some point this year?

MR. HEWITSON: Before the witness answers, I just want to lodge an objection that it assumes facts not in evidence. There is no evidence of the time frame over which Texas procured battery storages. I don't know if the witnesses know that information or not. But there is no evidence in the record of what the time period was from when Texas started the process to when it had the battery storage on process. So I just want to make that objection for the record.

COMMISSIONER MCDONALD: I am going to deny the

objection. I want to hear the answer, if you have one. If you don't, you don't have one.

A (Witness Grubb) Yes. So I don't know anything about the Texas issue. But from our standpoint, when we do RFPs, there is obviously the process of it. But most importantly is the evaluation of every bid from a generation value standpoint and then the evaluation from a transmission standpoint.

And so you are talking at a month -- months and months for us to study the transmission planning aspects of it. And that's important. Because when we do an RFP and we get the bids in, we evaluate every single one of them from a generation value standpoint. Then we get to a competitive tier, and we take all of those and study from a transmission standpoint. So we know that when we add those resources, we can get delivery service from them.

And so, when you look at that time frame, the last capacity RFP we did was over a year for that; and the ones we have got going forward are going to have a whole lot more volume, which means more bids to evaluate. And battery energy storage solutions are great. They are going to have a lot of flexibility. But when you study them from a transmission standpoint, you study them from their discharging, for supplying needs, and charging. And so it adds volume.

So the RFP process for us is the majority of it is the company's evaluations that have to be done to make sure that we know the value of those resources. And so when I talk about time to do RFPs, that's part of it. The other part of it is, if it is not an existing resource, you have got to evaluate transmission and likely build transmission projects. So we have, again, identified locations where you don't have to do delivery.

Again, completely supportive of the RFP process. 27 RFPs; 20 we have done; 7 we are going to be doing. If you have time to do it. We don't have time to do it here.

VICE CHAIRMAN ECHOLS: I mean, we do know that after that winter storm over there, that PSC commissioners lost their jobs; ERCOT directors lost their job. Panic set in. And that they probably did a lot of things over there that cost more than it should so that that would never happen again; right? So they were in some damage control mode, wouldn't you agree?

MR. GRUBB: I would agree, and I believe there was also some mention -- I have to remember the article where they also identified they need dispatchable resources and dual fuel. So to your point, a battery solar, they are all great. Takes a diverse fleet. But you have got to be able to make

sure you have some reliability dispatchable components, too.

BY MR. CARVER:

Q Thank you. So -- but again, putting aside whether you can expedite the two and-a-half year process, could you not solicit bids for build transfer agreements? In other words, you have identified -- and in this case, you have -- so I guess coming out of the 2022 IRP, you have the McGrau Ford facility, Cherokee County, approximately 270 megawatts.

In this interim IRP, you have proposed Robins Air Force Base, 128 megawatts, 49.5 megawatts at Moody Air Force Base. So that's a combined 178 megawatts. Then another -- an unidentified location, but 200 megawatt. And as you said, instead of solar-plus storage, it is storage to be charged by solar?

A (Witness Grubb) Correct.

Q 200 megawatts storage, 200 megawatts solar. Could these not be done as a build transfer agreement to allow for a competitive bid format?

A (Witness Grubb) So I will let Mr. Bush -- I think he has already talked about him reaching out to developers and doing those types of things. But we are absolutely going to allow build transfers in our All Source RFP. But you don't have time to do -- you have still got to

do transmission evaluations. You have got to do all those things. And so from a timing standpoint, it is not just the RFP process. It is the other.

And so build transfers are going to be allowed, and there was a lot of interest from the RFI in that. So our future RFPs are allowing. I think the utility scale allows for build transfers.

Q It does.

A (Witness Grubb) And so that is something we can do, but you have still got to go through the competitive solicitation process for those. But, I mean, what we are looking at now is we are working with developers for company-owned because we don't have time to go through an RFP and compare that price to others.

Q So let me -- and you may have answered this, but, again, it -- Staff Attorney Thomas's questions kind of prompted me to this. So we -- in the 2022 IRP, we had discussed, you know, I guess what ultimately wound up happening with the Commission decision, unanimous decision by the Commission, was to allow Georgia Power to self-build the McGrau Ford storage site, Cherokee County, but then to allow the market 500 megawatts.

And so it was really -- the intent was, at least as I recall -- again, it is almost two years ago now that we were sitting here doing this -- that we were going to see

how that process worked compared to how the competitive bid process worked. But the timelines are not aligned; right? Because we haven't even gone to an RFP yet for the competitive bid procurement.

So can you -- do we have a timeline yet when that RFP is going to be released this year?

A (Witness Grubb) So I don't know the specifics, it will be this year. But, Commissioners, it is important to remember that the request for storage in the '22 IRP, McGrau and the 500 megawatts, is for two-hour batteries to serve as operating reserves to continue to allow renewables and intermittent resources to be added to the system. They have capacity value, but the intent of that RFP is around operating reserve resources for the continued advancement of solar on the system.

We are still going to do that. We still need to do that. The '22 IRP, every RFP and everything out of the '22 IRP absolutely is being worked on. Absolutely needs to keep going forward.

When that need year advanced, we had to -- we had to identify capacity resources. And that's what we are doing. It doesn't change the other RFPs, McGrau, it doesn't change any of that. But because you don't have time to do an RFP, we identified, again, system megawatts that are available in first year of need, market available the same

time, and the deployment of resources for storage and CTs.

And so it doesn't change any of that. The intent was different. But even if you tried to move that up, you don't have time to have things on-line by the end of '25, '26, '27.

Q Just one final question, because it is -- again, it is -- this time frame is the issue of concern. It is the two and-a-half year process time length that it takes. You need these resources end of 2026, 2026 time frame. So I guess my question is -- and we go back -- going back in time, again, the 2022 IRP, we did not have the Inflation Reduction Act passed yet. I think, in fact, Senator Manchin was still holding that up. He hadn't gotten his gas pipeline yet. And then, we had a lot of additional loads that have not come in. Your testimony and your prefiled testimony go through that extensively.

My concern is is that we -- that this has been filed, and we -- we are up against the eight ball, and we can't run an RFP process because of the exigent need. But if this request had come in earlier, then we could have run an RFP process to do it.

A (Witness Grubb) If we had known more than two years before we knew, you could have run one. And so we have -- we have -- we saw the load forecast increasing in the latter half of '22. But the importance of this plan is

you still didn't have to add resources sooner for the first several increments of that load forecast. The All Source RFP would identify a wider range. Your capacity need got bigger in '29, but it didn't advance. And so you would have had to have known two years ahead of time to be able to go through an RFP process.

And again, we absolutely support the RFP process; but in this case, we have the opportunity to serve all of this load and put downward pressure on rates, and the only way to do it is with the resources we identified and the resources we can develop. We will continue to do everything out of the '22 IRP. We have got tons of work going on on that. This is to add onto that, to be able to handle this once-in-a-generation probably type of load forecast increase.

MR. CARVER: No further questions. Thank you.

MR. GRUBB: Thank you.

MR. CARVER: Thank you, Commissioners.

COMMISSIONER MCDONALD: Clean Energy Buyers Association?

MR. DUNBAR: Good afternoon.

COMMISSIONER MCDONALD: Good afternoon.

MR. GRUBB: Good afternoon.

MR. DUNBAR: Before I begin, I just wanted to briefly correct a statement I made earlier in

response to Commissioner Pridemore. The Clean Energy Buyers Association has over 400 members. I believe I said over 100. There is over 90 members with operations in Georgia. It includes large tech companies, automakers, banks, a wide variety of members. I thought I would list just a few to give the Commissioners a flavor of the members.

Members include Amazon; Google; Meta; Microsoft; Target; Walmart; Coca-Cola; Lockheed Martin; Boeing; Rivian; Honda; Toyota; Visa; NASCAR; Dow; Cargill; Visa; Mastercard; Lowe's; IHG Hotels, where I am staying here in Atlanta, and as well as a number of clean energy providers. And we have prepared the list, as you requested, Commissioner, and that should be filed into the docket by the end of the day.

COMMISSIONER PRIDEMORE: Thank you.

MR. DUNBAR: Thank you.

CROSS-EXAMINATION

BY MR. DUNBAR:

Q Turning to the questions. Again, my name is Scott Dunbar, counsel for Clean Energy Buyers Association.

Gentlemen, are you familiar with the clean energy goals of any of your current customers?

A (Witness Grubb) Yes. So, I mean, I am not

specifically aware of every single customer we work with; but I know when our Customer Choice group, Economic Development, works with them, that's part of the discussion, so...

Q Are you familiar with the clean energy goals of any of the new load customers that you have signed service agreements with that motivated this IRP update?

A (Witness Grubb) Yes. I am not personally aware of them, but I think we have gathered that information as a company. I don't know if anybody else up here knows.

A (Witness Evans) Yeah. Generally aware, but not the specifics.

A (Witness Grubb) Yes.

Q And when you say "generally aware," what exactly are you generally aware of as far as the clean energy goals of these new customers?

A (Witness Evans) That different customers have different levels of clean energy goals implemented at different years.

Q And some of those goals include customers who have publicly committed to be powered by clean energy, 100 percent of their operations powered by clean energy by certain years; is that right?

A (Witness Grubb) That's my understanding, yes.

Q Okay. But you are not -- not aware of any

specific examples that you guys can speak to today?

A (Witness Grubb) Not specific ones, no.

Q Okay.

A (Witness Grubb) And I am sure they are all a little bit different, as well.

Q Okay. When Georgia Power developed its load forecast and specific capacity proposals in this docket, did Georgia Power account for these clean energy requirements of its customers or the goals of these customers?

A (Witness Grubb) Not specifically, but, you know, as we have talked about, Commissioner, we have got a lot of programs that we offer to customers; and my understanding is when our Customer Choice group is meeting with them, we have discussions around those programs. But, no, we didn't -- not initially, but we did put together a plan that serves the load and is consistent with our fleet transition approach at Georgia Power.

Q And what do you mean by the fleet transition plan exactly?

A (Witness Grubb) So we have talked about, in the IRPs, and the '22 IRP set us up well, that we are continuing to move towards clean, safe, reliable, and affordable energy and transitioning the fleet to lower-emitting resources. But the way we do it, working with this Commission, is it is a combination of reliability, economics in that transition,

and so that's exactly what we are doing here.

Q And with respect to the voluntary programs, we can go through the details if you would like, but would you agree that those programs have certain minimum requirements that customers have to meet in order to participate?

A (Witness Grubb) Yes, generally. I don't remember all of them, but, yes, they do.

Q So 15 megawatts might ring a bell as the minimum peak load requirement for the CARES program. Does that sound right?

A (Witness Grubb) Yes. I think there is different pieces of the CARES program. I think for the large load one, that may be the case.

Q Okay.

A (Witness Grubb) But I will agree with you that there are requirements that have to be met.

Q So if you are -- well, smaller probably isn't the right word. But if you are -- you are not a small customer if you are 10, 12, 13, 14 megawatts of peak demand, but if you are below that peak demand minimum for those programs, you won't be able to participate in the voluntary programs; correct?

A (Witness Grubb) Yes. I can't remember the different aspects of CARES, but I will agree with you that there are some customers that don't meet the requirements.

Q And the programs have carve-outs; correct? There is limited amounts of capacity available for different categories of customers; correct?

A (Witness Grubb) Yes, that's correct. Based on the fact that you can only deploy certain amounts, and we have got to procure definitive amounts of megawatts. And so we do parse those up to make sure that we are -- we are, you know, offering those to as many customer segments as we can.

Q Okay. Turning now to a topic that has been discussed. I will do my best not to repeat any questions. With respect to the All Source RFP that was approved in the 2022 IRP -- and you discussed this in your direct testimony at the bottom of page 23, top of page 24. And it states, "The Georgia Power plans to increase the amount of capacity it will seek to procure in the upcoming All Source RFP to address the increased capacity needs in the 2029-2031 time frame."

So by how much does Georgia Power plan to increase the amount of capacity that it will procure through this upcoming All Source RFP?

A (Witness Grubb) So it will be based on the outcome of this IRP update and then also the forecast that we do. So the way we do RFPs is we look at the capacity need when we solicit the market, and we will provide a range, because over the time of that RFP, we will have an

update on the load forecast or two.

And so at the end of the day, the load forecast that matters is what we do when we certify it. And so right now I think -- I would have to go back and look -- give me just a second to get to my chart. The amount coming out of the 2022 IRP was -- would have been in the -- through the 3,500-megawatt range or so. Maybe a little bit less than that.

Now you look over, we need about 8,500 megawatts. But that's going to depend on the impacts of this IRP update and if we get any load forecast up between there. But it will be thousands of megawatts available to the market in that RFP.

But again, procedurally, what we do is when we file that -- when we bring that RFP to the Commission this year, with the range to procure, we will do that, we will go through that process through the next year-and-a-half, and we will update it with a load forecast before we ultimately decide the amount of resources.

Q Okay.

A (Witness Grubb) But it is thousands of megawatts.

Q You touched on this briefly in the last line of questioning. Can you explain why the RFP process typically takes two and-a-half years?

A (Witness Grubb) So we have said two to two and-a-half years. So there is pieces of it. Some of it is there are time period requirements, per the Commission rules, that sometimes are shortened, that are in two parts. So you have got part of that up front is to make sure that we get the documents -- the RFP documents and the PPA documents done so that the market knows what they are bidding to. And we need to allow enough time for the market to give their comments on the documents, as well. So there is that.

Then when you start moving into the actual process, again, you've got to have time to take the bids. You have got to do your generation evaluation on them. And it is driven by a lot of things. It is driven by the types of resources you are allowing to bid in, the volume of them, if you are going to have a refresh or not, those types of things. And then that takes four to six months, depending on the volume, about four, and then you have got to do transmission evaluations.

So if you look at our last RFP, that was about four months and then about six months. But when we look forward to the All Source, and you think about 6,000 -- 5,000, 6,000, 7,000 megawatts, you could be evaluating much -- many more megawatts than that on bids. And so it is just the amount of time that it takes to evaluate those,

because Commission, as you know, at the end of the day, what we are looking at is making sure we understand the value of any of those resources on a generation and a transmission aspect. Have to evaluate every single one of those bids. You have to build them in the models. You have got to study them, and then you have to study the portfolios.

So there is some procedural parts to it, but a big part of it is the evaluation. And that's what we have been doing, and it is a great process. At the end of that, the Commission knows exactly what we got for the market and what the impact of it is.

And we are supportive of it. Have always been supportive of it. But per Commission rules, there are exceptions when things change, and that's what we are in right now.

Q Did Georgia Power have to do an analogous transmission evaluation, such as you just described, for the resources that it has proposed in this update?

A (Witness Grubb) We did. So we did a screening evaluation of the resources we were looking at. And we are updating that now to capture the final resources that we have proposed plus the higher load level. But the difference is you are talking about 8, 9, 10 resources, not 80. And so it is same process, but it's just a volume issue.

Q How long did it take for the resources you have proposed in this docket?

A (Witness Grubb) So a few months. I am trying to think of when we -- so it would be about three months just to take the final resources and update it to this one. So, again, it is still more limited. But those are -- they are very robust models when we provide them to staff. Commissioners, it is terabytes of information, so it is a very robust process.

Q Good thing you have lots of data centers.

A (Witness Grubb) Nicely played there. Yes, we do. A lot of data nowadays; right?

Q So it is Georgia Power's position in this proceeding that the new -- the near-term capacity need is sufficiently large and sufficiently near term, that it is facing extraordinary circumstances, and these extraordinary circumstances are what necessitated Georgia Power making this update filing in between its regularly-scheduled IRPs. Would you agree with that?

A (Witness Grubb) That's right. Driven by the change in the load forecast.

Q And it is also Georgia Power's position that these extraordinary circumstances warrant relying on certain exceptions to the general competitive bidding processes established by the Commission's IRP rules; correct?

A (Witness Grubb) Right. As allowed by the rules. That's correct.

Q So if the Commission agrees that Georgia Power is facing extraordinary circumstances, then presumably the Commission could order Georgia Power to take other extraordinary actions that are outside the normal course of business or might require rule waivers. Would you agree?

A (Witness Grubb) It depends on which one you are talking about. I don't know what rule waivers there are. These are not waivers. These are applications of rules that have been in there for 32 years. And so, sure, the Commission could. I mean, I am not an attorney, so I can't speak to what all -- you know, what is by rule. But these are not -- these aren't waivers. These are actually rules that are in the Commission's rules.

Q And I am not going to ask you to talk about legal issues or --

A (Witness Grubb) Good.

Q -- rule waivers. But just as an example, the Commission could theoretically direct Georgia Power to complete the All Source RFP that it is about to issue on an expedited time frame; correct?

A (Witness Grubb) They could. Physically, I don't think you would gain any time from the deployment of resources. And so, it would be -- you are trying to make up

the three years in a few months, and so, you would -- if you had to address this all through the All Source RFP, you would be pushing load growth and downward pressure on rates out three years.

If we did none of the resources and said the All Source, you cannot speed the All Source up enough to have things come on in '25, '26, and '27.

Q And that's because, as you explained earlier, that the process typically takes two to two and-a-half years; correct?

A (Witness Grubb) Yes. Even going with two years, what it really is -- there is several factors. One, there is not existing resources, that we are aware of, that are out there that could respond, and so you are talking about new construction.

COMMISSIONER MCDONALD: That's been stated several times.

A (Witness Grubb) Yeah.

BY MR. DUNBAR:

Q Georgia Power typically requests certification of new resources in the following IRP; correct? I believe in this case you said that resources would be certified in the 2025 IRP; correct?

A (Witness Grubb) No, not necessarily. I don't think Mr. Bush nor I said that. So resource certifications

are happening all different times, depending on what the process is. Majority of the time, they are not in an IRP. They are in an RFP certification. So we did have the '22 IRP where the RFP's results were certified in the IRP, but every other RFP is by itself.

And so, what we are -- what we are doing here is we needed to move forward with development and contracting of these resources. The resources that we were able to contract, we have brought forward to certification. But we are asking the Commission for approval to move forward with the others, and we will bring them as we have them available.

Yates, we filed the contract Friday, so we are closer to that one. We will be filing certification of that soon. And then as we get the contracts that are required for a certification filing for the others, we will bring those to them.

Q Could the Commission -- could the Commission direct Georgia Power to modify some of the requirements of the upcoming All Source RFP to encourage a larger and more diverse set of bids?

A (Witness Grubb) So the requirements in that RFP haven't been set yet. The IRP granted approval is a capacity resource RFP, so it needs to be dispatchable and controllable. But that all happens through the RFP process.

So as the Commission knows, we'll work on documents. We'll work with staff on those documents, the RFP and the PPAs, and we'll bring those forward to the Commission. So, ultimately, the Commission approves the resources in the RFP when they approve the RFP documents.

Q So I think that means that there is still time for the Commission to provide direction as to what that RFP is going to look like.

A (Witness Grubb) Yes, absolutely. Right now it would be similar to our last one, in that you're looking at capacity resources that are controllable and dispatchable, so it's been -- in the past, it's been gas resources; it's been standalone storage; it's been storage plus renewables. And so, yes, ultimately, the Commission does eventually approve the resources being selected there.

But again, this is a capacity RFP. So there are requirements that it needs to meet. So the company and staff will work on those documents, take comments from the market, and then we'll ultimately bring documents to the Commission for their approval.

Q The Commission could direct Georgia Power to accept bids from smaller resources, for example, in the 20- to 100-megawatt range; correct?

A (Witness Grubb) They could. One of the reasons that we look at 100 megawatts is economies of scale, but

also, when we've talked about the volume and talked about the timing, every bid has to be evaluated separately. So if you're talking about 6,000 megawatts, and you start taking bids that are 2, 3, 4 megawatts, the volume of the bids that you have to evaluate -- I'm not saying there's not value in them, but it could double or triple the amount of time you would have to do the RFP.

So we've always tried to take a minimum that, from a capacity standpoint, from a fleet operation standpoint, you've got enough size that you can see them and monitor them in real time and dispatch them. So that's why we've usually had 100 megawatts there.

Q To take another example of potential extraordinary actions, the Commission -- the Commission could direct Georgia Power to revisit the results of the 2019 All Source RFP and perhaps evaluate -- reevaluate some resources that submitted bids in that RFP?

A (Witness Grubb) You said the 2019 RFP?

Q Correct.

A (Witness Grubb) I'm not -- the one that came out of the '29 IRP?

Q That's right.

A (Witness Grubb) Yes. We refer to that one as the '22 to '28. Just want to make sure I'm talking about the right one. But, no, those bids are withdrawn, and those

resources -- most of those resources are the ones that Commissioner Shaw and I were talking about had been bought. So you can't go back to bids in RFP. You can solicit them. And we did approach them in the RFI to see if they had anything, and you want them to bid in the next ones.

But once that RFP is selected, we release all those bids, and most of those were all sold. The existing ones. The new ones just have to bid into the next RFP.

Q You spoke with EPA counsel about using the RFP for the CARES program to procure -- to procure capacity, and I believe you said that it's not a capacity RFP; it's an energy RFP. What's stopping you from changing that, adding to it, evaluating bids differently to procure capacity through that process that's already ongoing?

A (Witness Grubb) So capacity is -- has two terms. So, again, that RFP is for energy value resources, not dispatchable controllable, to meet reliability needs. So when we talk about capacity, obviously, solar bids have megawatts that -- you can refer to them as their capacity. So when we're talking about RFPs, though, it's an energy resource RFP or a dispatchable reliability RFP.

And so the CARES RFP is for solar to provide energy value and RECs for subscriptions and those types of things. It's not about resources that we use to meet reliability in summer and winter peaks.

Q But if a bidder submits a solar-plus storage bid, what's stopping the company from negotiating with that bidder to turn that bid into a capacity resource?

A (Witness Grubb) Well, so that RFP requirements -- and I don't know them all -- has to allow that use case. But what would be a better use of that is that same developer can bid that into the All Source RFP this year from a different use case. So they could have a storage site that they bid in to the All Source that's around that use case or use it to support solar. So you can't do it in the same RFP because the intent of that RFP is specific.

Q And I guess that's what I'm getting hung up on. I understand that that's the intent, but what exactly is the obstacle that prevents you from pivoting, given the extraordinary circumstances you're facing?

A So I am no lawyer. But the RFP documents and the purchase power agreement documents that are approved by the Commission that have already been sent to the market are around that specific resource solicitation.

Q Okay.

A (Witness Grubb) And again, we have the opportunity through the other RFPs. So we still need the solar RFPs, and we still need to move forward with those.

Q Okay. Just one more example of potential

extraordinary actions. Theoretically, the Commission could direct Georgia Power to join or explore joining an RTO to ensure that it has sufficient access to capacity resources. Would you agree?

A (Witness Grubb) I would -- I don't think an RTO gives us any different -- I think the ability to get capacity is fully supported by this market structure. The issue right now is building the capacity and building the transmission. The Commission can do what they want, but this -- this isn't a market structure issue in terms of timing. It is the ability to physically build infrastructure, generation, and transmission to serve the need.

Q And I understand that that might not be your preferred solution, but would you agree that's something the Commission can order?

A (Witness Grubb) They can consider what they would like to. I'm not going to tell them they can't.

Q On page 31, you assert that Georgia Power needs to rely on these exceptions to the Commission's RFP requirements that we discussed earlier to, quote, "Facilitate the timely deployment of supply-side resources needed to serve customers while mitigating the risk that the market either cannot provide enough capacity or will not offer enough firm and dispatchable resources to reliably

serve customers," end quote.

So Georgia Power is not -- as we've covered -- has not yet issued the All Source RFP that was approved in the 2022 IRP; correct?

A (Witness Grubb) That is correct. But that RFP is not to address needs in the '26, '27, and '28 winter period.

Q But since it hasn't been issued, you don't actually know, currently, how much capacity the market is prepared to provide; correct?

A (Witness Grubb) In that, no. We've got some indication from the RFI, but not the RFP itself.

Q And for the RFI, that was limited to resources of at least 100 megawatts; correct?

A (Witness Grubb) Right. To match the All Source RFP.

Q And it did not -- the RFI did not actually offer respondents the opportunity to enter into a contract with Georgia Power; correct?

A (Witness Grubb) That's correct. That's why it was an RFI, not an RFP; right.

Q So there was no direct, tangible benefit provided to companies that responded to the RFI; correct?

A (Witness Grubb) I can't speak to the benefit for them. It was a benefit to us to have information on

what types of contracts and what types of technologies the market's interested in bidding. I would assume there's a benefit to them if they responded, though. So I think that -- I think -- I can't speak to it because I'm not a developer, but we had a lot of responses, so there must be a value to them.

Q And just to be clear, you're speaking about that the respondents presumably perceived some benefit in responding, but the company didn't actually give them any tangible benefits in exchange for responding or as a result of providing a great response; correct?

A (Witness Grubb) No. I mean, it's an RFI for exactly -- you know, exactly that. But what it did do is it did help us verify that there's not existing resources available in this short time frame -- the time frame we're looking at in the IRP, and gave us a lot of good information about what people are interested in bidding in to the All Source.

Q Turning to page 29, the testimony states that market participants selected through an RFP process, quote, "Are not obligated to serve Georgia Power's customers and are not able to address the company's capacity needs on the accelerated timeline identified in the 2023 IRP update," end quote. As you've said -- as you've indicated many times.

When a market participant signs a power purchase

agreement with Georgia Power, wouldn't you agree that market participant is obligated to sell energy and capacity to Georgia Power by contract?

A (Witness Grubb) Yes. So they're obligated to meet the requirements of that contract. If they don't deliver, there's penalties in there. But what we're really talking about here is if we didn't identify the resources we have to deploy and did an expedited RFP or anything else, the market doesn't haven't to respond, and then you don't have time to physically build them.

So it was more around the short-term time frame than PPAs that we get certified before the Commission. So, yes, they absolutely have obligations in the contracts once they're signed and certified to the terms of that contract.

Q And I believe -- okay. Are you aware that many other states do not have any requirements that a certain percentage of the utility-supplied resources be owned by the utility?

A (Witness Grubb) I don't know what other states do. I know this Commission's had that in place since the rules were set. And I think it's just an acknowledgment from the Commission that there is, at the end of the day, a reliability benefit to company ownership; but there's also a benefit to PPAs. And I think that's why they're a balance.

I can't speak to other utilities. I do think

there are other utilities that have a percentage of solar they build that have some of their goals they build. They build company-owned proposals outside of RFPs. But I don't know every state. But I think the Commission was right in setting that, that there's a balance that needs to be had there, and it's worked well.

Q Are you aware that utility-owned resources make up a much smaller percentage of supply-side resources in other states?

A (Witness Grubb) Nationally or just other states? I don't know. I don't know what those are. But I would say, again, our market structure here in Georgia is to have the RFP process and have the company participate and have that standard there. And so I can't speak to what other states do. Some of those, the generation's not even owned by the utility if it's an RTO, so I don't think you can make a comparable comparison between states that have different market structures.

Q You took my next question right out of my mouth.

A Whoops. Didn't mean to.

Q And on page -- on page 30, you state that if Georgia Power procured all of its -- all of the capacity it needs through PPAs, the company's ownership percentage would fall below 70 percent, which, quote, "would be inconsistent

with Commission policy and present system reliability risks," end quote. We've talked about the Commission policy. Have you provided any evidence in this proceeding about the nature of these purported reliability risks?

A (Witness Grubb) No. So what we -- we are -- by the order and the rule, we're supposed to -- we are obligated to notify the Commission when we would fall below that minimum percentage that was set by the order back in 2001. So that's what we're doing, and noting that if we didn't build, then we would fall below it. We're required to notify the Commission when we do that.

And so when we talk about reliability risk, we're generally talking about the difference between ownership and a purchase power agreement, that we talked a lot about, Commissioners, in the 2022 IRP about storage. PPAs have benefits. Ownership has benefits. But when you get to the end of the day, on a reliability standpoint, PPAs are -- PPAs are good, but at the end day, they're a financial contract, and that's different from our obligation to serve. And so when we talk about reliability, we're talking more around that.

But I will say during Winter Storm Elliott, we had higher performance from our company-owned resources than purchase power agreements, because we can do things like go winterize after polar vortex.

The other aspect of ownership that's important to keep in mind is flexibility. Mr. Bush talked about that some earlier today. When things change on the system, you have got to have seen that in the contract structure that might be a 20-year contract structure, or else you're held to it. On the ownership side, we can move.

So again, we are supportive of PPAs, but when you think about we used to have all of our reliability risk in the summer, we still have PPAs where all the capacity payments are in the summer, even though the reliability risk is in the winter. The new ones don't. They balance it out. But that's the type of thing you can't respond to in a PPA.

So when we talk about reliability, it's just that ownership gives you more flexibility. Not saying that every PPA hasn't performed, but there's just a difference between that, which I think the Commission acknowledges by that balance.

Q That's all the questions I have. Thank you, gentlemen.

A (Witness Grubb) Thank you.

MR. DUNBAR: Thank you, Commissioners.

CHAIRMAN SHAW: All right. Heelstone Renewable Energy?

MR. GALLOWAY: No questions, Mr. Chairman.

CHAIRMAN SHAW: No questions.

Georgia Association of Manufacturers.

Mr. Jones?

MR. JONES: Thank you, Mr. Chairman.

CHAIRMAN SHAW: How are you?

MR. JONES: I'm good. How are you this afternoon?

CHAIRMAN SHAW: Good.

MR. JONES: Staying warm in here. Not so much outside.

MR. GRUBB: Yes, we're warm up here, Mr. Jones. Yes, it's a good day to be inside, though.

MR. JONES: I'll try not to make it too much hotter for you.

MR. GRUBB: Do as you need, Mr. Jones.

CROSS-EXAMINATION

BY MR. JONES:

Q Good afternoon, Panel. My name is Clay Jones. I represent the Georgia Association of Manufacturers; and the good news is that Mr. Thomas covered a lot of the same ground that I was going to cover, so I think I can hopefully be very efficient today.

So this -- this projection that you have of explosive growth, that's the basis for your suggestions of these measures to address that growth, right, over the next --

A (Witness Grubb) I'm sorry. I missed the last part.

Q The explosive growth that you're seeing in your projections, that's why we're here today, for you to propose these measures to try to meet that growth; right?

A (Witness Grubb) That's the change since the '22 IRP, that's correct.

Q Now, since you filed the IRP update, I'm just curious, are there any of those assumptions about the growth that have changed? Are you continuing to look at your forecast?

A (Witness Grubb) So I'll let Mr. Valle speak to that. We do know that in the case you have got to, you know, have a strict aspect of resources that we wanted to identify, so that's what we have identified here. The Flex Capacity plays into that a little bit, but I'll let Mr. Valle speak to the other question.

A (Witness Valle) Yes. So we haven't -- we haven't created a new forecast, obviously, because the forecast that we have provided supports the request for this Commission. But we have monitored the activity in the economic development pipeline. And I would say that from the time that we completed the forecast for the 2023 IRP update until the end of 2023, the amount of megawatts in the pipeline have grown about 25 percent.

Q Okay. So sort of building off of Commissioner Pridemore's questions earlier, these are mostly competitive loads, right, that are driving this need; correct?

A (Witness Valle) Yes, that's correct.

Q Do you assign a degree of confidence about how much of it will materialize and how much of it won't?

A (Witness Valle) Yes. Depending on where each project is in the economic development pipeline, we assign different likelihoods. To be more specific and to elaborate a little bit further, if there are -- think about stages in the development; right?

So the first step in the stage is the state selection. So customers come here. They evaluate between Georgia and other states. That's the first -- the first decision point.

The next one, once they have selected the state of Georgia, they're selecting the electric provider; right? And then after that, they become our customer to serve. The closer they get in the economic development pipeline to become our customers, the higher the likelihood is incorporated into the model.

A (Witness Grubb) So Mr. Jones and Commissioners, I would add one piece to that. So when you look at the pipeline, it's 17,000 or more megawatts, and we're seeing -- our load forecast is projecting 6,600 megawatts of growth.

So there's some confidence in the fact that we're having a measured approach to it. We're not asking for 17. So there's confidence that you've got that continued growth there. We don't see it slowing down. But just wanted to add that flavor, too.

Q And, again, the company has taken the position that it expects the revenues associated with this incremental load to fully offset the cost of the resources that you're proposing in this case?

A (Witness Grubb) That's correct.

Q And would you characterize the measures in this case as interim in nature? In other words, next year we've got another IRP coming up. You already starting to work on that, Mr. Grubb, or you thinking about that?

A (Witness Grubb) We've got some people working on that. You probably are, too.

Q Yeah.

A (Witness Grubb) Yes, so we do -- you know, interim in nature. Some of the resources are; right? So the PPAs are interim in that they get us to the All Source RFP. The other resources are not, but they'll help us with those needs.

And so, we will be updating the load forecast. But to be able to meet this need, we need these resources. So we will update it, as you say, and we'll be back in '25.

So some of the resources are in them, but we see this as going to be load growth that's going to be here for quite a while.

Q And, of course, there's been a lot of discussion today about the two PPAs you're proposing to enter into, one with your affiliate, Mississippi Power, and one with the Santa Rosa Energy Center in Florida. And as has been noted, there was not an RFP process for those; right? There was not time; correct?

A (Witness Grubb) Right.

Q But they were identified by Georgia Power as supply side, I believe the rules say, capacity resources of extraordinary advantage that require immediate action. Is that the rule that you are relying on --

A (Witness Grubb) That's correct.

Q -- to not have an IRP process? Okay. And collectively, they would provide 950 megawatts of generation capacity; is that right?

A (Witness Grubb) In the summer. I think it's a little higher in the winter. But, yes, just shy of 1,000, you're right.

Q Okay. Let focus on the Mississippi Power PPA. And that's, again, a five-year term that runs from January a couple weeks ago through the end of 2028; is that right?

A (Witness Grubb) That's correct.

Q And the purpose is to help meet that short-term three-year winter capacity need that begins in 2026; right?

A (Witness Grubb) That's right.

Q So you would agree -- and I think you have agreed already -- that this and the Santa Rosa PPA, neither of them are needed for the next two years?

A (Witness Grubb) Correct. But, you know, again, if you don't get those two years, you're not getting the third, fourth, and the fifth ones. And, Commissioners, when we saw the year of need advance three years and said, How are we going to go meet this load, we wanted to get as much existing resources as we could. And so, that's why we looked at Mississippi and Santa Rosa.

Had there been some others, we would've done those, too. Because they are less risk in terms of the need to build. So what we have put together is a portfolio that was able to get as many existing resources as we could, but Santa Rosa was actively bid into other RFPs and Mississippi was as well. And so, they would not be here if we had not executed them. They would not be available to Georgia Power if we had waited.

Q So Mr. Thomas asked you some questions about the IIC or the Intercompany Interexchange Contract; right?

A (Witness Grubb) Correct.

Q You know what that is?

A (Witness Grubb) Yes.

Q And just to be clear, that's a FERC-approved agreement; is that right?

A (Witness Grubb) That's right.

Q And the members of that IIC are Alabama Power, Georgia Power, Mississippi Power, and Southern Power?

A (Witness Grubb) That's correct.

Q And you -- Mr. Thomas also asked you about whether you could have procured this surplus capacity through the IIC instead of a PPA; right?

A (Witness Grubb) Uh-huh.

Q And your response was that it would have been temporary, I think, was your -- is that your testimony?

A (Witness Grubb) Well, so some of it would have been unavailable because Mississippi was set to retire. The others will probably need to be extended to get to the end of those terms. And so to have that length, Mississippi had to take some actions. But, yeah, so reserve sharing is not an obligation of any of the companies.

And so when you start looking at reserve sharing four and five~years out, there's so many things that move that you're not sure that those reserve sharing aspects are going to be there. And, again, that's settlement. From a planning standpoint, we coordinate our planning, but those resources were going to be gone from the --

Q But the IIC does provide~-- you know, you're familiar with the operating committee under the IIC?

A (Witness Grubb) Yes.

Q All right. So the operating committee is where there is a representative from each company, including Georgia Power; right?

A (Witness Grubb) Yes.

Q So this surplus capacity~-- you know, the fact that the Mississippi Commission was telling Mississippi Power, this wasn't needed for their customers?

A (Witness Grubb) Right.

Q Is something that would have been known by Georgia Power for how long, three~years or so now?

A (Witness Grubb) I can't remember which IRP it was, and that's true. But, again, we weren't in a position of looking at system reserves that we needed them, so, yes, we would have known through that.

Q But you've known about it. And the concern the Mississippi Commission had was to remove uneconomic costs from retail rates for their customers there; right?

A (Witness Grubb) Right, because they were well above their target reserve for years.

Q But that wouldn't require mothballing the plan or retiring it. It could be used, for example, to meet a need that Georgia Power might have; right?

A (Witness Grubb) I mean, yes, but, again, that's what the PPA gives them that reserve sharing may not have given them certainty on.

Q But do we -- I guess the question is, do we really think that Southern Company, knowing Georgia Power has this need, would allow that capacity to simply not be used if Georgia Power said, Hey, we want to utilize the IIC to use this capacity because it's not needed by Mississippi? Don't you think that the parties could have agreed to that?

A (Witness Grubb) That's what the PPA does is it makes sure that Mississippi has the certainty that they need that they will get revenue on those resources, and it gives Georgia Power and this Commission certainty that they'll be there. So through the IIC, that's not there.

I agree with you that Mississippi absolutely -- I don't want it to come across they don't care about reliability --

Q Right.

A (Witness Grubb) -- but when you look at their customers, it would have been for our need, which is why the PPA is the way to make that relationship set up where we could do it.

Q So, on the one hand, the PPA creates obligation that you're talking about, instead of doing it through the IIC, but there would be some advantages for customers who

are doing it through the IIC; right?

A I'm not sure. There was -- there would be less certainty. And then the pricing that the PPA has is reflective of what we expect reserve sharing to be through those years. So there's actually a little more risk on the reserve sharing side for their customers than the PPA.

Q Okay. Now, I want to be careful here because I don't want to get into trade secret numbers. But are you saying -- you're taking the position that the capacity purchased through the IIC would not be less expensive than what the PPA calls for?

A (Witness Grubb) The current price we expect to be very similar. So we go to the market and set that reserve sharing price. But what we base the price of the PPA on was current market prices through that period of time.

Q Okay. But -- so for -- I don't believe the price under the IIC is a trade secret; right? That's a public --

A (Witness Grubb) One year out, I don't think it is.

Q Right. So for 2024, would you agree with me, subject to check, that it's $73.20 per kilowatt year?

A (Witness Grubb) Subject to check, that sounds about right.

Q Which would equal $6.10 per kilowatt per month.

A (Witness Grubb) Uh-huh.

Q Right? And, again, I don't want to use specific numbers. I don't want to violate any trade secret issues, but could you compare that price with the price of the capacity payment in the PPA?

A (Witness Grubb) It is. It's important to know that's a one-year price, not a five-year price. And there's differences there, but it's slightly lower than what's in the PPA. But, again, the PPA was -- we talk about reserve sharing, it was to make sure that those resources were there. The pricing was based on our knowledge of market pricing, what Mississippi was seeing in the market, what we were seeing in the market through *Sui, because it's very comparable to the Santa Rosa PPA, as well.

Q Okay. Okay. Now, another advantage for customers if you had done this in the IIC would be that customers wouldn't have to pay for an additional sum, right, because that's not part of the IIC?

A (Witness Grubb) Correct. Again, we're not sure the resources would have been there, but, yes, we don't pay an additional sum through the IIC.

Q Okay. Now, I think you testified in response to Mr. Thomas that even with the additional sum, that you believe that there's still a downward pressure on rates;

right?

A (Witness Grubb) Right. So we have included that in our analysis.

Q But if you didn't have the additional sum, it would be even more downward pressure on rates; would you agree?

A (Witness Grubb) It would. But, again, additional sums allowed by law and we're being consistent with the 2022 IRP.

Q Okay. That's my next question. So the additional sums that you're requesting is $3 per kilowatt year, and you selected that number because that's what the Commission approved in the '22 IRP; correct?

A (Witness Grubb) Correct. We'd all just gone through that.

Q Yeah.

A (Witness Grubb) So we figured we would just be consistent with that, very similar contracts.

Q Sure. And I understand some logic there. But let me ask it this way: There's a difference between those PPAs and these; right? In other words, those went through -- and, again, I'm not criticizing that you didn't go through a competitive process here.

A (Witness Grubb) I understand.

Q Because that's not my point. I understand the

timing. But those PPAs went through an RFP process with an independent evaluator and a full competitive analysis as to what the best available resources were; correct?

A (Witness Grubb) That is correct.

Q Okay. Would you agree with me that part of the purpose of having an additional sum for PPA is to compensate the company for foregoing a self-build opportunity?

A (Witness Grubb) That's one of the three notes -- reasons noted in the law.

Q And, further, the purpose of an additional sum would be to incentivize companies to not always build a new plant but to seek the most cost-effective resources for customers, which might be a PPA?

A (Witness Grubb) That's correct. That's part of it as well.

Q But, in this case, you're responding to a very extraordinary situation; right? You've never seen anything like this, have you?

A (Witness Grubb) I have not.

Q Okay. And so would you agree with me that the company is pretty well incentivized to find whatever resources it can to meet these interim needs?

A (Witness Grubb) Well, the company is always incented to meet the needs of the capacity, RFP or not. So any time the company is asking for capacity resources, we

have the incentive to meet that need. And so for customers -- and so again, same treatment as in the 2022 IRP, for these PPAs, because without them, you know, there are a lot of value to them. They allow us to meet a third of this need that we have.

Q Would you agree with me that the Commission has the authority to select a different number for the additional sum if it were to recognize the differences between these PPAs and the ones from 2022 as being different?

A (Witness Grubb) They could. Obviously there are a lot of similarities, but, yes, that is up to them.

Q All right. I would like to move on to deferred accounting~-- some deferred accounting questions because the company is asking the Commission to defer recovery of the capacity payments under both the Mississippi Power and Santa Rosa PPAs; correct?

A (Witness Grubb) That's correct.

Q And, to be clear, I'm not an accountant, but let's try to see if I can try to understand --

A (Witness Grubb) Me neither.

Q Maybe if you have an accountant up there, they can clarify it for both of us. But deferred accounting means that Georgia Power will fully recover the capacity payments under both PPAs at some future time; correct?

A (Witness Grubb) Right. And the request is to put that in the next rate case window.

Q Okay. So you would request it in the next rate case?

A (Witness Grubb) Yes.

Q Does Georgia Power propose to accrue carrying charges on the deferred capacity payments?

A (Witness Grubb) I believe -- subject to check, I think that's what we have reflected in there.

Q Are those based on your midpoint ROE, or are they based on something else?

A (Witness Grubb) It was part of the math in the DR that we submitted, Mr. Jones, but I can't remember the details on it.

Q And you mentioned earlier that you are trying to remarket some of this capacity. Does Georgia Power also~-- if it's accruing carrying charges on the deferred capacity payments, would it also accrue carrying charges on the revenues?

A (Witness Grubb) I know we're recommending deferring those revenues to reduce the amount of deferred costs on those PPAs, but I'm not sure of the treatment on that aspect.

Q Would you agree with me it would be a good idea to treat them symmetrically in fairness to customers --

A (Witness Grubb) And I don't -- we would have done that math, Mr.~Jones. I just can't remember the details of it.

Q Are you also trying to remarket the Santa Rosa PPA capacity?

A (Witness Grubb) We are.

Q Okay.

A (Witness Grubb) And so we've already -- for the commissioners, we've talked about this, so Mr. Jones is right. We've already remarketed 500-megawatts from those PPAs for the first -- for '24 and '25, and we are continuing to look at additional sales out of that and then also Santa Rosa.

Q So, thus far, you've sold 500-megawatts of the 980?

A (Witness Grubb) That's right.

Q Is that right?

And I guess the -- you had a question, I believe, where you said it would offset -- it might offset the additional sum, as well.

Do you remember that question from Mr. Thomas?

A (Witness Grubb) Right.

Q Wouldn't that depend on the market price of what you get for this capacity, though?

A (Witness Grubb) It would. And I was -- yes,

it would, and I was more thinking the one we've already done; they're in a similar neighborhood. We haven't seen the market -- we haven't seen the market reduce. I mean the market is still really tight. But we would look at that. I would say, though, that it's still beneficial for customers if we don't exactly get recovery. It's still better than not being able to sell it. So any revenues we can get, we will look to get market pricing, and it would help customers.

Q So you're aware that -- or let me ask. There are other utilities in the Southeast who are experiencing some substantial load growth, as well; right?

A (Witness Grubb) That's correct.

Q And you just mentioned that available capacity is becoming tighter; right?

A (Witness Grubb) That's correct.

Q So it should be fair to us to characterize the capacity market as a sellers market right now in the Southeast; would you agree?

A (Witness Grubb) Probably so, yes.

Q And do you think Georgia Power, if it wasn't receiving a deferral, would have more incentive to market that capacity?

A (Witness Grubb) No. I don't think the deferral changes our incentive at all, whether we're

recognizing it immediately or deferring it, we know that anything we can sell benefits customers and helps put further downward pressure on rates. So we're going to go get the deal we can -- the best deal we can get regardless of deferral.

Q You can choose not to defer the cost, right, or not request that; right? It's not required that you do it?

A (Witness Grubb) It's not required. As I spoke to this morning, what we're doing is deferring it to match up with years of need in which those resources are needed, especially because that wasn't contemplated in the '22 rate case.

A (Witness Evans) Additionally, Commissioners, it aligns the deferral of those costs with the revenues that caused the cost to be incurred. So from a cost-causation standpoint, it's very appropriate to match up both those costs with the revenues in the load that costs --

Q But if Georgia Power -- okay. Well, do you contend that if you did not~-- if the Commission did not grant your request to defer recovery, under the PPAs, are you contending that would result in you earning an ROE below your authorized midpoint?

A (Witness Grubb) We don't know what our earnings will be there. So it definitely would make them lower, but I don't -- I can't project what our earnings

would be there. Again, our reason for deferral, like we've done in similar cases, is to move those events that weren't contemplated in the rate case to a later time.

Q So right now 10.5 is the midpoint of your authorized ROE range; right?

A (Witness Grubb) That's my understanding.

Q And that's midpoint, but it's really -- it runs from 9.5 to 11.9 currently?

A (Witness Grubb) Uh-huh.

Q Now, in 2022, Georgia Power reported $234 million of earnings above -- at that time, it was a 12, not 11.9. And that was~-- a large part of that was refunded to customers through the sharing mechanism; correct?

A (Witness Grubb) Yes. That's my understanding, subject to check, but, yeah, I'll take you at your word there.

Q Can you approximate the annual expense of these two PPAs?

A (Witness Grubb) Yes. It's trade secret, but it is provided in that.

Q Okay. I want to be careful there, too.

A (Witness Grubb) Yeah.

Q Would you agree with me that it's less than~-- can you agree that it was less than 234 million?

A (Witness Grubb) Yes. Less than earnings in

that year. Again, we don't know what our earnings will be in '24, '25 --

Q Well, it probably wouldn't surprise you to learn that the company's done a very good job of earning. I mean, their earned ROE -- well, I'm not trying to be flippant here, your earned ROE has always exceeded the midpoint ROE, dating back for about a decade or so; would you agree?

A (Witness Grubb) Subject to check.

Q And the mechanism provides that in the unlikely event that you were to have a year where you earned below the bottom, you can file a rate case or request to defer other costs to stay within the range; right?

A (Witness Grubb) That is my understanding.

Q Okay. All right. I want to move on to one last topic, which is the -- just one second, the battery storage, BESS, and solar. You're proposing to add three new battery resources to pair with solar resources in this case; right?

A (Witness Grubb) That's correct.

Q And two of those, we talked about already, they total altogether about 178-megawatts, is that the right number?

A (Witness Grubb) That's right.

Q Will be addressed -- will be added on the --

I'm sorry -- the site of existing facilities at Robins and Moody?

A (Witness Grubb) That's correct.

Q But there's no existing resources for the third one, right, at this time, for the third battery storage?

A (Witness Grubb) There's no generation resources there. I think Mr. Bush can help me here, but there's a point of interconnection that we're looking at taking advantage of. But, yes, the solar has to be built along with the storage.

Q And, again, I would advise the panel, and I'll be conscious too, that I know some of this information is sensitive, so I don't want to be too specific about it. But you're basically, as I understand it, proposing and -- well, let's do it this way.

You filed a new economic analysis last week?

A (Witness Grubb) We did. That's correct.

Q Do you have that in front of you?

A (Witness Grubb) We do. Give us just a second.

Q Sure.

MR. JONES: This isn't an exhibit, Mr. Chair, but if you'd like, I can bring a copy up so the Commissioners can follow along with what we're --

BY MR. JONES:

Q So this is the public disclosure version. We

should be able to talk off this document without any concern of revealing anything we shouldn't. So the resources that are included in this economic analysis are compared on a dollar-per-kilowatt basis; is that right? I mean, it doesn't show the numbers there, but is that what you're comparing here?

A (Witness Bush) Is it 4.1? Are you referring to --

Q I'm sorry. Yes. It's page 5, public disclosure. I realize I didn't give you what I handed them. It's the summary of study results, number 4, on page 5. And I can hand you a copy if you would like.

A (Witness Bush) Yes, that would be good if you don't mind.

Q Okay. Have you had time to look at it, or do you need a minute?

A (Witness Grubb) Yeah. You can keep going.

Q Okay. Well, let me try to ask a question then. And if you need, please take the time that you need.

So I guess my next question was, the resources that are included in this economic analysis are prepared on a dollar-per-kilowatt basis to allow for a level comparison between projects of different sizes; would you agree?

A (Witness Grubb) That's correct.

Q Okay. So, again, without discussing any

specific numbers, do you agree that the paired solar and battery resource, which, again, is the 200-megawatts plus the solar facility that's not built yet is ranked here as the most expensive of these resources; would you agree?

A (Witness Grubb) Yes, that is correct.

And, Commissioners, the way we've done this evaluation is very similar to the exact same way we do an RFP evaluations. So Mr. Jones is correct. We've ranked them in terms of that value, but all the resources are needed, but, yes, you're correct on that.

Q I guess what I'm trying to get at is, is it fair to say that because the battery component of the paired resources -- is it the same technology type? I mean, or is there a difference in technology between these three?

A (Witness Grubb) No, no. Between Robins and Moodys and the 200 BESS plus solar, no. It's the same battery technology.

Q So then are we to assume that the dollar-per-kilowatt being higher is due to the fact that it's paired with a particular solar resource itself? Is that what's causing it to be more expensive?

A (Witness Grubb) I'll let Mr. Bush add on here. But part of it is, you're having to build that solar. So you're right, Robins and Moody have existing solar there. We're having to build the solar resource here, but I don't

know if there's any other differences to point to.

Q Okay. Does your application or anything in your filings evaluate the cost of these individual components, breaking it down between the battery and the solar?

A (Witness Grubb) Yes. I think, subject to check, I think in the SAM financial models, we would likely have the different cost components and all the details in what we've evaluated. So we've provided revenue requirements, and so it would be in there. I think by contract we probably have it broken down.

Q I guess I'd just request if you could provide it to us, a hearing request for that, to anybody who --

A (Witness Grubb) We'll check and see if it's been in any DR models.

Q I couldn't find it, not that I'm not necessarily the right person to look for it.

A (Witness Grubb) We'll get that for you.

Q Thank you.

So would you agree that as an energy resource, that the levelized cost of energy is a reasonable metric for evaluating the cost of a proposed solar resource?

A (Witness Grubb) I'll let Mr. Bush add there, too. I think it is. I think there are some things that are a little -- that aren't perfect about LCOE compared to how

we do it, but I think generally it is. But I'd let Mr. Bush speak to it.

A (Witness Bush) I would say, Commissioners, generally, it is. But the problem, particularly for solar, number 1, every site is different. Number 2, you have to take into account interconnection, and number 3, these are three of the major ones, not all of them. It's just the AC -- what we call our AC/DC overbilled; right?

And so we design our solar facilities to optimize, as best we can, the energy component and the capacity component. So you may actually build a lot more solar panels and have clipped energy so that your profile of the solar facility is different than someone else might.

So LCOE takes all that cost into account over -- so life assumption also impacts it, as well. So all of that has to be considered. So it's not a trivial comparison. You really do have to do a little more diligence, you know, to make an appropriate comparison. But, generally speaking, you could say that that is one approach to take from an LCOE perspective.

Now, it doesn't tell you anything about the capacity value. It's just LCOE, assuming a certain capacity factor. So, again, all that -- if you take all that into account, then you can make an appropriate comparison.

VICE CHAIRMAN ECHOLS: Let me ask you about a

BESS plus solar question. I know Southern Power has acquired a couple of those original large solar arrays, Taylor County, Decatur County.

Did you-all approach Oglethorpe Power about acquiring some of their green power EMC larger arrays that you could then couple with BESS as maybe a possible way to save money buying an existing solar array down in -- you know, down in south Georgia?

MR. BUSH: We haven't specifically done that with a Southern Power resource, but we have, in fact -- you know, Georgia Power has significant PPAs. And they have -- some of their larger PPA providers, we have been in discussions with.

You have to -- again, the contracting mechanism -- if I have a PPA, I have to then ensure that the PPA is held harmless. I have to ensure that they want to do a transaction with us. I have to ensure that they have available land to do that. I'll have to have a sharing mechanism if I'm going use the same GSU as they have, so there's a lot of factors that go into it.

If I add the Oglethorpe component, there's another transmission piece that I have to think about there, as well. But the concept that you're talking about is exactly what we're trying to do,

Commissioner.

BY MR. JONES:

Q Is the levelized cost of the proposed solar resource we were just talking about, the one that's ranked sixth, isn't it in excess of their -- Georgia Power's avoided cost of energy?

A (Witness Grubb) The -- I'm not sure. You're asking for the actual cost of that?

Q Yes. The levelized cost of energy of that project, could you compare it to your -- without -- again, without discussing the number, but compared to your avoided cost --

A (Witness Grubb) Yeah, it may be -- but I think the important thing is that solar is really to charge this storage, not just purely from its energy standpoint.

Q But it's the whole project, right, that has a levelized cost, you look at the whole project?

A (Witness Grubb) Right.

MR. JONES: Mr. Chairman, that's all I have today.

CHAIRMAN SHAW: All right. Thank you, Mr. Jones. We're going to give the panel a little quick break. It's 4:00. Ten minutes enough?

THE PANEL: Yes.

CHAIRMAN SHAW: All right. We'll see you back

at 10 after 4:00.

(Whereupon a break was taken.)

CHAIRMAN SHAW: All right. We will get started back. Next on the appearance list is Georgia Center for Energy Solutions. Mr. Hubbard, did he show up?

(No response.)

CHAIRMAN SHAW: All right. Georgia Coalition of Local Governments.

Ms. Brown, how are you?

MS. BROWN: I'm doing wonderful. Thank you. Good afternoon, Panel and Commissioners.

THE PANEL: Good afternoon.

CROSS-EXAMINATION

BY MS. BROWN:

Q I would like to begin with a question about the DER co-location and customer-owned programs. Did those have a defined capacity contribution that the company is relying on?

A (Witness Evans) No, not yet. That will be based on -- and I don't think I've said this yet.

So because those programs are positioned to supply-side programs, each one of those individually will go back before the Commission for certification. And based on those resources and the capacity equivalent to that time will reflect the resource plan once approved.

Q So is the idea that you're going to have this program and learn more about it and then you can hopefully incorporate it in later IRPs?

A (Witness Evans) No. I wouldn't say it that way. I would just say that the uncertainty around the capacity equivalence and when those resources show up, because it's not just about the construction time of the resources, it's also about, if it's a new facility, when that facility is going to come online.

So there's several different variables that come into play when trying to determine exactly when and how much we should put on the resource plan. But for the reasons that I just said, it's also imperative that we get the program approved now such that that process can begin and that capacity can be realized as soon as possible.

A (Witness Grubb) So Mr. Evans is correct, but to your point, as we get those certified, they would be reflected in plans following that.

Q Okay.

A (Witness Grubb) We just haven't done so yet.

Q If we can go back to a conversation that you had with Commissioner Echols earlier about solar and storage, you were saying one of the reasons that it might not be fully appropriate for this growth in load is that one of your primary drivers is winter mornings.

Am I remembering that correctly?

A (Witness Grubb) So I don't remember saying that specifically on -- it depends on the intent of the program and the resource. For these resources that we're proposing here that are storage charged with solar, we would intend those. If I said that, I was more probably talking about a solar storage combo in a solar solicitation, but for these resources in several use cases, you could.

Q I believe it was a rooftop conversation.

A (Witness Grubb) Okay.

Q So if we can talk about rooftop solar for just a minute. Are current rooftop solar customers receiving any kind of price signal or other incentive to store up their energy and dispatch it or use it on a cold winter morning?

A I'm not sure. I know that they get paid -- they get paid for their energy. So unless there's a situation where they want to shift that, but I don't think they are right now. Of course again, that program is more just around the energy value, so I don't think they are right now.

Q Well, there's no specifically constructed program trying to use solar as a winter resource?

A (Witness Evans) So whenever you refer to rooftop solar, there's -- you know, to go back to the '22 rate case where we talked about that metering. There's two

components there. There's that generation that's consumed on site, and then there's that generation that's then pushed back out onto the grid.

Which one are you referring to with your question?

Q I'm specifically referring to solar and batteries and if there's been anything set up to encourage customers to reserve that energy for cold winter mornings?

A (Witness Evans) Well, I think through the price signal of it completely offsetting their retail rate for what's consumed on site, there's a tremendous price signal there.

Q Okay.

VICE CHAIRMAN ECHOLS: Let me ask you about when these customers dump their batteries. We know that about half the solar, you know, array is going and now have batteries associated with them. It's becoming popular.

So the EV time-of-use rate that a lot of solar customers are on, isn't it -- that overnight cycle completed at 7:00 a.m., is that when it clicks over to the -- to the middle shoulder of rate, does that sound right?

MR. EVANS: It's somewhere around there. I'm not exactly sure of the exact hour, but subject to check, yes.

VICE CHAIRMAN ECHOLS: But no special price signal that we've created that would say to that customer, hang on to it until 7:00 in the morning, then dump your battery at 7:00. You know, and if you will dump your battery at 7:00, we'll compensate you X; right? We don't have anything like that yet; right?

MR. EVANS: No, not yet, Commissioner. And I think, you know, whenever we look at batteries and the benefits that they can potentially provide going forward from a behind-the-meter customer type. The real benefit there is being able to dispatch them when we need them; right?

Going back to Winter Storm Elliott, using your example, whenever we needed capacity on the system during Winter Storm Elliott, was well before 7:00 a.m. So if we were incenting customers to a fixed price signal, right, that was not dynamic that we cannot dispatch and send that to them whenever we actually needed it, they might have not responded, waited until 7:00 a.m. when we really needed it at 4:00 or 5:00 a.m.

VICE CHAIRMAN ECHOLS: But if the utility could -- I mean, these batteries have an app. I mean, they're -- it is possible for you to get a look

at them if the customer agreed to do that. And even to give you control over those for the right price.

If you could do that, would it be valuable to you to access those home batteries and be able to dump them at 7:00 in the morning on a cold winter morning? Would that be valuable or not valuable to you?

MR. EVANS: I think, under the right use cases -- and that's something we're looking at for the '25 IRP, as Mr. Grubb said. Also, as he said, you know, looking at DERMS in the -- not just the visibility as you said. But also, as you said, the controllability from the DERMS platform would be critical in unlocking those value streams.

VICE CHAIRMAN ECHOLS: Thanks.

BY MS. BROWN:

Q So Georgia Power provided a letter of support to GEFA, the state energy office, for a $250 million solar for all application, which by all accounts from the EPA, Georgia will receive an award, someone in Georgia will. And that program is anticipated to bring solar and battery storage to tens of thousands of disadvantaged Georgia households over a five-year period.

Has Georgia Power had any engagements with anyone working on this or thought about how they might be able to

leverage those resources that are, for sure, coming to our state during this period of need?

A (Witness Evans) I can't speak to that funding specifically. But as me and Commissioner Echols was just saying, the capabilities and benefits of those types of resources can bring is something that we're looking at for the 2025 IRP.

Q Are there any investments that would be helpful to make now or pilots that would be helpful to run now so that you're ready to hit the ground running in 2025 when that funding is in hand and ready to deploy?

A (Witness Evans) Well, I think it's a critical component in the funding that's already underway that the Commission approved in the last IRP, was for the DERMS platform, and we'll look at revisiting what some of those capabilities are in the '25 IRP that, again, unlock what some of those value streams are.

Q Okay. Continuing on the subject of onsite resources, a question I get regularly living in a city that has a lot of warehouses is, is there any consideration of solar on those warehouses, solar and storage, company-owned or customer-owned, has that ever been part of the consideration, given that that load growth is right there, there's that load to meet it?

A (Witness Grubb) So I don't know any specifics.

I mean, customers can do that. I do think we've seen some bids that have looked at that. But I don't know that we've got a specific company program. I know usually it's a little more expensive than the traditional DG or utility scale. But customers obviously can do that if they want to.

But I -- again, as we get ready for the '25 IRP, that's something we can think about. But I'm not personally aware of what we're looking at there. But it is a potential space.

Q So there was no company economic analysis?

A (Witness Grubb) I'm not saying there's not. I'm not aware of one. We would have to check on that.

Q And a related question, there's ample opportunities for efficiency improvements at all customer class levels, residential, commercial, industrial, and many of these solutions can be deployed very quickly and have ancillary benefits to customers. Recognizing the loads are going to continue to grow, and that electrification is in full swing, why wouldn't energy efficiency be mentioned anywhere in this proceeding?

A (Witness Grubb) So for one reason, and Mr. Evans can join in here, one is, again, the amounts that we're looking at and the timing that we need to deploy these resources was what we were mainly focused on.

But I think the other point is, if we identify

items in the '25 IRP, they still would be able to help in this time frame. It's not -- you don't have to move forward as fast with those as you do building dispatchable resources.

I don't know if you want to add.

A (Witness Evans) Yes, a couple things there. You know, as you're well aware, we're right in the middle of developing what those programs are going to be and presented in the next IRP. The technical resource manual was filed in December, the technical economic and achievable potential study will be filed this month.

Right after that, we will begin developing what those program look like based on those achievable screenings for the '25 IRP. It's also important to remember that Georgia Power has committed to supporting a meaningful increase of DSM in the '25 IRP.

A (Witness Grubb) And as you noted, as the cost on the system changes, that will, through our normal process, get captured in evaluation of energy efficiency programs.

A (Witness Evans) That's right.

Q Moving on to larger resources. For this IRP update, the company is only proposing one new solar project, the 200 megawatts paired with 200 megawatts of storage. As you know, there's a 10 percent noncompetitive energy

communities bonus that is available for projects located in energy communities of which there are at least seven in Georgia.

Did the company evaluate the possibility of locating a project in those areas so that instead of a 30 percent tax credit, we could have a 40 percent?

A (Witness Grubb) So we are. I think as we move forward into the next rounds of RFPs for capacities, those are among the things we will be looking at.

Q Okay. Moving on to the proposed combustion turbines at Plant Yates, the company is proposing to make these dual fuel due to the costs and challenges of securing firm gas supply; is that correct?

A (Witness Grubb) That's true. And it's consistent with how the rest of our CT fleet is structured, as well.

Q Is your expectation that those supply constraints will get better or worse with time?

A (Witness Grubb) Supply constraints on the gas side?

Q On the gas side.

A (Witness Grubb) Depending on what happens, they could get more challenging. But what we've done is made sure that we're able to take advantage of the gas that's already at the Yates site for the Yates 6 and 7 units

and to make sure we have the availability to do that.

So that is something we'll look at going forward at Yates is the ability to firm that up. But, again, there are some challenges with it why -- which is why that dual fuel nature of it is so important.

Q In your response to the data requests Staff JKA222, you suggest that the new plant Yates units will run on oil primarily in peak periods of the summer and winter when that gas supply is constrained. Because, as you know, many of the loads being added are high load factor and other utilities in the region are also going after that limited gas supply. Is it possible that these units may end up running on oil the majority of the time?

A (Witness Grubb) That's not our expectation. We expect the gas to be available the majority of the year similar to what we have now on our CT. So if you look at our CT now that's dual fuel, that doesn't have firm transportation, the vast majority of the time they run is on natural gas.

Now, in general, CTs don't run a whole lot. They're single digit, maybe low teens capacity factors on a year, meaning they run about 10 percent of the year or less. But from that standpoint, it may; but we've got gas on the Yates site that we could take advantage of through the mid-30s.

And these will be the most efficient CTs on the fleet. And they're more efficient than Yates 6 and 7. So we've got a lot of gas that we can use even if things don't develop, but we'll just have to look at that as we continue to move forward with the gas fleet.

Q Would you say the current gas/oil split is representative of what's going to happen in the future, given that there is extraordinary load growth?

A (Witness Grubb) Yes. We have the rest of the fleet, right. So these are capacity resources that we still don't expect to find a lot of time. They may run a little bit more, but we do expect that to hold. But, again, these will be the most efficient CTs on the system. And so they will be able to have energy savings when other CTs would run. These will be the first ones on the system that go.

Q The EPA is currently reviewing comments on a proposed rule for new source performance standards for greenhouse gas emissions, and this applies to both new and existing fossil fuel resources. The current proposed rule, which is still being evaluated for final implementation, excludes small and load capacity factor resources, but there's a chance that this will change before the final rule. And there's also a chance that carbon legislation will materialize in the future. These units are set to run for 45 years.

What is the company proposing, as a safeguard, to make sure residents and other ratepayers aren't saddled with a stradded asset.

A (Witness Grubb) So there's a lot that we'll unwind in 45 years, right, but when we look at our expansion plan modeling, for example, where we look across a range of carbon pressures, not the new rules specifically, but carbon pressures, it still shows the need for dispatchable gas in the form of either CTs or combined cycles.

And so until there's new technologies that we aren't aware of yet, you're going to need dispatchable resources for cold, winter mornings like today and tomorrow for many, many years to come. So we -- a lot has to play out in 45 years, but we feel confident that you're going to have to have these types of technologies. And this will be the most efficient CTs.

I would expect these would be the last CTs that we have on the system, if we decided to move out of them. But we feel strongly that you're going to need these types of resources.

And when we look at carbon goals, you hear "net zero," those types of things, there could be technologies that are developed to help net that out from a CT standpoint. But there's always going to need to be some resources that can hit those really peak times.

Q Let me ask you this: Which is generally more efficient, a combustion turbine or a combined cycle unit?

A (Witness Grubb) So combined cycle unit. They take longer to build, which is one of the reasons why we did not propose one in this case, and they are more expensive from an up-front standpoint, but they do have a lot of value.

So you need a mixture of both. And we have a mixture of both on the system. But from an efficiency standpoint, it's combined cycles, but different use cases. They're both available.

Q So you did actually consider an additional combined cycle unit in your transmission screening analysis, you did a transmission analysis for the Lindsay Hill facility in Alabama, and it was ruled out because the transmission upgrades couldn't be completed in time.

Did the company evaluate whether storage as a transmission solution could overcome those transmission barriers?

A (Witness Grubb) We did not. In the transmission screening, we looked at -- as we mentioned this morning, redispatch, operating guidelines, reconductoring. We don't usually look at batteries as a potential to remove transmission projects mainly because they have to be charged and so they serve as a load. So most of our transmission

contingencies are not usually solved with a battery.

Q But when thinking about existing resources versus something that you have to construct with all of the attended risk of construction, isn't it worth doing an additional evaluation to see if that existing resource could be used?

A (Witness Grubb) So I can't remember exactly everything we studied. But if you can't -- I don't think you could add a battery that would run down there for five years and resolve every contingency. So that's an existing resource that we looked at. But you're talking about having to build some projects that allow for it to deliver across many different peak times. And so we see lots of value for batteries from a generation standpoint. We have not really seen cases yet where it's a great transmission contingency avoidance project.

Q And then moving on to the cost of this portfolio of resources that's been proposed, it's been discussed, all else being equal, we expect the projected revenues to cause that downward pressure on rates. But this, of course, is predicated on assumptions about the load growth, completing projects on time and on budget, future fuel costs, environmental regulation.

What safeguards are in place to make sure that if the company over projected the amount of capacity that's

needed or under projected fuel costs or misjudged future climate legislation, what's there to protect the ratepayers in that case?

A (Witness Grubb) So a few things there. One, is, like I mentioned this morning, the amount of revenues that we used. We had a smaller level of the external adjustments applied on the revenues compared to what we have in the case. So we were leaving -- there's more likelihood that it will be higher than those revenues than lower.

The other thing would be we can adjust the resource plan depending on when those loads would -- if those loads don't show up, we could adjust the resource plan. The future RFPs would be smaller. We wouldn't have to identify quite as many batteries. So there are some things we can do on the resource side.

But what we looked at was really those first three years of capacity need, 26, 27, 28, feel very confident in those numbers. And then as Mr. Evans mentioned, over time that delta between the revenues and the declining revenue requirements actually grows.

Q And then one final question for you. There's been a lot of conversation today about the ownership requirement that the Commission has and this idea of potentially having third-party resources. And it comes back to there's an All-Source RFP rule that requires a certain

amount of time. But there is another exception for resources under 30 megawatts.

Was that ever given any consideration of looking at some of these battery resources that are planned or on the system through a PPA but that fall under that other exception?

A (Witness Grubb) We didn't look at that because of the magnitude of the need. We needed to identify the large projects that we could do, and so we did not. Doesn't mean we can't look at them, but we have not identified any yet.

We were trying to get to the largest solar sites we could do to build that storage, and we need CTs in the mix. And so we looked for some bigger hitters than the 30 megawatts, but you're right, that is another exception.

Q I guess I lied about it being the last question. Real last question, is it easier in some cases or in most cases to interconnect a smaller resource than a larger one?

A (Witness Grubb) It can be easier depending on where it is.

Q Okay. Thank you so much.

A (Witness Grubb) Thank you.

CHAIRMAN SHAW: Georgia Interfaith Power and Light.

CROSS-EXAMINATION

BY MS. WHITFIELD:

Q Good evening, Commissioners, gentlemen. My name is Jennifer Whitfield, and I represent Georgia Interfaith Power & Light. And I have done my best to strike all the questions that have already been covered that I had on my list. But I did want to ask a few follow-ups about the RFPs.

We talked about the All-Source RFP that's planned for resources beginning in 2029. And, Mr. Grubb, earlier you said that you could discuss with staff potentially trying to accelerate that process. Did you approach staff and talk to them about accelerating that process --

A (Witness Grubb) So we talked --

Q -- or did the company?

A (Witness Grubb) So we have talked to staff around that RFP. It's -- there's no way you can accelerate it to meet these needs, though. And so we've talked to them about it some, but that RFP is '29, '30 and '31, you can't speed it up in terms of making up that three-year move and the need for capacity.

So we have had a lot of discussions with staff on that. We're still having discussions, working on that schedule of what to put in that RFP. But even if we had approached them in June, even if we had started months ahead

of time, you can't make up the three years, so...

Q Sure. If you can't make up three years, could you make up a year and a half?

A (Witness Grubb) Not from the deploying new resources, I don't think you can. So, again, the only reason -- the only way an RFP would address these needs is if there were 3,000 megawatts of existing resources out there with transmission, not under contract that we could go do an RFP and sign, and that's just not the case we live in.

So that All-Source RFP is crucial to get right for '29, '30, and '31. It's going to be for thousands of megawatts, but it's not the vehicle to address these needs. Because, again, the load forecast was increasing, but the three year earlier deployment of resources happened in June. And even if you sped it up, you wouldn't have been able to accommodate it.

Q So I don't want to mischaracterize you, but I think what I'm hearing from you is you haven't asked to accelerate it because it's, in your view, not possible to do it fast enough to meet the needs?

A (Witness Grubb) We haven't asked for acceleration of that to meet the needs in this IRP update.

Q And did you approach the Commissioners directly about that same question about accelerating the RFP process to meet the needs of this -- these -- this demand growth?

A (Witness Grubb) No. So we -- at the same time we mentioned and communicated with Staff in June that the year of need we moved at two years at that point, eventually it was three, you didn't have time to do an RFP at that point.

And so we started looking at what resources we could get and started identifying those and worked on those for several months. So even if we had come to the Commission, you wouldn't have been able to do it until June because there was no indication that the need year was earlier than '29 until June. And so even if we had come to the Commission and asked for expediting that RFP, or doing a new RFP, we would not be able to meet the needs in -- to have resources online by the end of '25, '26, and '27.

Q Okay. The CARES RFP, in September of last year, so just a few months ago, the company came to the Commission and asked to amend that RFP. Do you remember that? Were you involved in that process?

A (Witness Grubb) I was not -- it depended on how we amended it. I was not involved in the CARES RFP.

Q Okay. Well, at that time, are you aware of any discussions with either the staff or the Commissioners to amend the RFP to address the capacity need?

A (Witness Grubb) And this was September of '23?

Q That's right.

A (Witness Grubb) To amend which RFP?

Q The CARES RFP that's currently -- that's going live for bids pretty shortly.

A (Witness Grubb) No. So, as we discussed earlier, the CARES RFP is to add solar from an energy benefits standpoint and for subscription programs. And so, as you know, Commissioners, we've done lots of RFPs in the past. They're either for renewables from an energy benefit standpoint or capacity RFPs. So the CARES RFP is important and we need to do that. It's not the vehicle to meet these needs. So we wouldn't want to take the CARES RFP and not do it.

We heard some questions earlier from Mr. Carver. There's an importance to meeting the needs of adding solar to the system. And that's what CARES is doing. That RFP could not be amended to meet these needs or else you lose the ability to add solar through it.

Q I'm sorry. I missed the last part. You said or else you lose the ability to do what?

A (Witness Grubb) If you took the CARES RFP and tried to use it to meet capacity needs, then you're not adding solar through that RFP the way it's intended to do. That RFP is around -- is about adding 3200 megawatts of solar by the end of the '30s. And it needs to move forward. As we've heard, there's a lot of value to that.

Q And you're doing an effective job at describing the RFP as it's currently written. My question is about kind of thinking outside the box, thinking about Commissioner Echols' creative solutions that he's urging the company to consider.

So my question is not how it's written now, my question is: If you had conversations with staff or Commissioners, and I think what I heard is, you did not approach them and ask them to amend, change, expand the CARES RFP that's currently live in order to include capacity resources in addition to the energy resources you're discussing.

A (Witness Grubb) Right. We did not because when you look at the time frame to do an RFP and that you have to build new resources and transmission associated with them, it can't meet the needs by having resources on the line by the end of '25, '26 or '27.

Q Okay. Thank you.

I want to talk about the RFI, and the RFI that was issued --

MS. WHITFIELD: And Commissioner Shaw, Mr. Chairman, may Mr. Sherrier approach with an exhibit while I ask these couple of questions just to speed things along?

CHAIRMAN SHAW: Sure.

(The document referred to was marked for identification as GIPL Exhibit 1.)

BY MS. WHITFIELD:

Q This is an excerpt of the RFI, summary of results that Georgia Power filed. You probably have it in front of you. But I wanted to provide it just for ease of reference. In your testimony, though, on page 23, you conclude that the results from this RFI somehow demonstrate that there aren't resources that can meet the company's capacity needs by winter '25 to winter '26; correct?

A (Witness Grubb) You said page 23 of testimony?

Q Page 23 of your testimony. It's at the top, lines 3 through 7, I believe.

A (Witness Grubb) Yes. So in our testimony, what we say on line 5 is, we have no indication that there are additional existing resources that can meet the needs.

Again, that's because we do not have time to do an RFP and have construction of new resources. So if there had been an existing resource identified that was not under contract, we could have approached them in a similar manner we did Santa Rosa, but none of those were indicated.

Q Okay. And this RFI -- that existing resources, that phrase is doing a lot of work, I think, in that sentence. And, to be clear, the RFI is not -- was not just for existing resources, it was for existing resources and

new build so long as they could meet the scope of the RFI; correct?

A (Witness Grubb) That's right. It was not restricted to either. We wanted to know information on both.

Q Okay. If you could, in the RFI summary, there's an attachment to it. I've flagged it. Some of you have taped flag, some of you don't. But at Section 2.0, scope, of the attachment that describes the scope of the RFI, and it's the green taped flags for those of you who got them.

A (Witness Grubb) You're actually talking about of the RFI?

Q Of the RFI, the scope of the RFI.

So basically what it was asking for, what it was telling the market it was looking for.

A (Witness Grubb) Yes.

Q And I see there that it says it's looking for capacity resources available to commence delivery as early on or after November 2026. So that would be the winter of '26, '27 time period; correct?

A (Witness Grubb) That's correct. And no later than 2030, to also cover the period for the capacity All-Source RFP.

Q Sure. So help me with the disconnect because

your testimony says that the RFI demonstrates there's no availability for winter '25, but the RFI is for winter '26.

You weren't even asking for resources of winter '25; correct?

A (Witness Grubb) Yes. So we do -- yes. We do say commenced delivery as early as November 1st, 2024, should indicate such availability.

Q Yes.

A (Witness Grubb) So we did ask for that. But, yes, so we were looking -- also in -- when we were drafting this, I think, in August or September, that need year moved up with the final load forecast. So there was a -- I'd have to go back and look at the timeline, but '26 was actually the first winter need in the June update, and we updated it with the load forecast. We may not have had that final load forecast. But the point is, we were trying to look at the time frame covered by the IRP update but, just as importantly, the time frame for the All-Source RFP.

So the RFI was not just about the '23 IRP update. Had we identified some existing resources that we could go and approach, we would have done so. But it was just as much about the time frame that the All-Source was going to cover, for us to see what kind of technology was out there, to see if there were any contracts that may bid in in the '29 through '31 time frame, as well.

Q Okay. So let's look at some of the results, and that's flipping back to the beginning is where I put it. There aren't page numbers. So some of you have an orange taped flag, but it is --

A (Witness Grubb) The table?

Q The tables, Table 0-3-1 and Table 0-3-2, and it's in Section 2.4 --

A (Witness Grubb) Yes.

Q -- for the Commissioners.

So looking at these tables, by my math it looks like you have about 3,000 megawatts of energy storage systems for batteries and battery-like things, for the laypeople like me, bid in for '26, '27 and '28.

Would you agree with that?

A (Witness Grubb) Right. In those calendar years, so, yes, the '25, '26, '27.

Q Okay.

A (Witness Grubb) So an important part of this is, they're indicating that -- none of those are existing, and so they're indicating they could build storage by then. But, again, what you don't know and what the challenge is, is you don't know that you could take delivery from those, and it's highly likely that you can't. You've got to do transmission studies.

So you have to take those -- that information

would have to go through an RFP to set prices and evaluate the transmission. And so that means you can construct it there, that does not mean that you can actually take delivery from it.

Q So this RFI wasn't really, then, looking for resources that you could procure to serve your needs, it was looking for -- I mean, I guess I'm not understanding why a battery supplier would spend their time to bid in or to provide information for this RFI if the company's position is it's basically worthless information without an RFP.

A (Witness Grubb) It's not baseless worth information. So if you look at the front of the RFI, it says it's for the sole purpose of our resource planning activities. So it was not just about the earlier years. It was just as much or more about the later years.

And so had we seen existing resources that were available, we could have moved forward with those. It does help to know that those batteries are out there because if they're saying they could be online in '25, '26, '27, and they should be able to bid in and be available in '29, '30, '31. And so the RFI told us a lot of important things.

It told us, number one, there are no existing resources that we can go get and meet the needs in this IRP update. It did indicate that there's some existing ones that may bid in, in the All-Source IRP, which is good,

because that means of that 6500 megawatts, we may not have to build all of it, us or the market.

So if there's some existing resources that bid in, it helps you from a development standpoint. It also showed us that nobody indicated that they want to build new gas. And so as we start looking at the '29, '30, and '31, that's important for us to know that nobody -- that don't mean that they won't bid it in, but there's not an indication people are moving to gas.

There's a lot of interest in build transfers. So as we go through the RFP, we need to accommodate that, and there was a lot -- a lot of interest in storage. And so we got a lot of good information out it. But the RFI was never solely intended to meet the needs of the IRP, because, again, you have to identify the resources that you could move forward with, which is what we've proposed here.

If you started reaching out to these customers at the RFI, you would not have time to bring them online to meet the needs in this case.

Q Have you tried to reach out to these customers to see if they would be willing to engage in contracts on an accelerated basis, particularly the 2,500 megawatts of batteries that say they're available in 2026 or 2027?

A (Witness Grubb) Not yet. We've been focused on getting the resources we have here. I know Mr. Bush is

looking at some other areas, but I don't think it's these specific ones. Again, a lot of the times we didn't get any pricing information or transmission information. So not saying it's not something we can look at going forward, but we have not done it at this time.

Q Approximately, how many respondents, maybe a percentage of them, did submit cost information?

A (Witness Grubb) Well, so it wasn't -- it was pretty low. I don't think I did a percentage. It was only a -- it was the minority of them, though, that gave pricing information.

Q Like less than half?

A (Witness Grubb) Yes.

Q And for those who did provide pricing, did you do any analysis of the comparison between their pricing and the pricing that you're offering essentially to customers to buy as part of this IRP update?

A (Witness Grubb) We did not. Because, again, we don't know that we -- we don't -- we can't move forward and deploy those resources. We can move forward and deploy the ones we've identified. So we did not do it directly. But, again, the resources that we've identified can be deployed.

We've included those in the economic analysis. And we've also included those costs in the analysis with the

statement of downward pressure on rates. So we have not because, again, even if you did, these were non-binding prices. You would still have to go through an RFP to have the pricing set against all the different market participants.

Q Well, would you, because we're moving around the RFP for everything else in this RFP update; right? Like the Mississippi PPA and the Santa Rosa PPA, which typically would go through an RFP, so would you?

A (Witness Grubb) Well, so those are existing resources, and so they're different. You would have to figure out of those 2,600 megawatts, who to approach. So --

Q Yes, you would --

A (Witness Grubb) So we would have to have some means of doing that. And so an RFP would give you those means. We would have to come up with another means to do that.

And so what we've done with the battery energy storage systems is looked at facilities that we knew had existing points of interconnection that we could contract with because you've got to move quickly.

Q Yes. All right. Let's shift gears and talk about the ownership percentage guidance issue. The last time I'm aware of this issue being considered, really argued before the Commission is 2001.

A (Witness Grubb) I'm sorry. I missed your initial issue. I'm sorry.

Q Oh, no, no, no. That's fine.

But the last time I'm aware of the ownership percentage guidance this Commission has given being argued before the Commission is 2001.

Are any of you aware of anything more recent than that?

A (Witness Grubb) So we indicated in the '22 IRP that we would exceed 30 percent of PPAs in, I think, '28 or '29. So we did provide some guidance in '22.

Q Yeah. Other than that, are you aware of any other time when this has been sort of addressed by the Commission --

A (Witness Grubb) I have not. And we talked about it some earlier today. A lot of that was because when you look back over the last several decades and you looked at our need to build capacity, a lot of it was driven by a combination of load growth, but also PPAs rolling off. And so you haven't seen the amount of load growth that we're looking at now.

And so you usually had the ability to do purchase power agreements because they were driving a lot of the reason that you had a need. And so we were always close to that 30, but every time you got kind of close, PPAs would

roll off. But as you have inclines or increases in load like you do now, just naturally, it's going to become more of a need to address it than if it's flat load growth as we've seen in the last 20 years.

So the issues that the Commission considered back then around reliability were a little bit different drivers. My understanding, it was more around market dynamics and the importance of reliability in third-party PPAs. But, again, today, reliability has got other drivers, but I would say it's just as important, even more important than it was then, and as much dynamics. So that's the main reason it's never come up. But, again, we have the obligation to notify the Commission when we exceed the 30 percent.

Q Are you familiar with Georgia Power's position in 2001? I'm not saying it as a "Gotcha," I just want to -- ask you a question about it.

A (Witness Grubb) Yes. I haven't looked at it in quite a while.

Q Okay. All right. Well, in that case, in the interest of not playing Gotcha, this is testimony from Georgia Power from 2001, but my question is whether you agree with that sentiment today. So in 2001 -- imposing an additional constraint like the arbitrary limit on the amount of purchase power could have the unintended result of rejecting what was otherwise the best option for customers.

A (Witness Grubb) Yeah. So I think, Commissioners, the important thing to note in 2001, was the time when we were just starting to add new gas resources in the industry and doing PPAs. So I think that was one of the first outcomes where we were looking at a big capacity of RFP where PPAs bid into it.

And so, again, that was -- that statement is showing the benefit of PPAs. We're not saying that there's not benefits to PPAs. What we're saying is the balance is appropriate. So it sounds like that is saying that you had good resources from the RFPs. But, again, in 2001, that was in the infancy of the industry building out gas units and us doing RFP for capacity. So at that time, I think that's an appropriate statement. I think a balance is still a good thing for customers today.

Q All right. One more. Do you agree with the sentiment: It would do considerable harm to the competitive marketplace to have a rule, like a 70-percent ownership rule?

A (Witness Grubb) I can't really opine on that, not knowing all the dynamics in 2001. So I think again --

Q Well, I'm asking about your sentiment today, whether you would agree today. I know you can't -- I know you haven't revisited the whole 2001 transcript.

A (Witness Grubb) Yes. So I mean, I've said it

again: The company is absolutely supportive of the RFP process. You have to hear the number again, 27 since 2006, including the 20 we've done and the 7 that we're going to do out of the '22 IRP. So we absolutely see a value from the market, but there's a value to ownership, as well.

And so I think this market since 2001, we've done all of those RFPs and contracted with multiple different facilities that have impacted and given benefits to customers. I don't think the market's been dampened by it. And I still think that it's a good balance.

Q Yes. And I know you've mentioned today that, I think, 20 RFPs have been conducted by the company. I think is the number you shared.

A (Witness Grubb) Right.

Q So certainly there's been a lot of experience. I did want to note, though -- or ask about the fact that, at the time in 2001, Georgia Power was arguing against a hard limit, a firm limit that would sort of prevent the Commission from being flexible. And think I heard you today, though, I'm not entirely sure, that you agree that you could -- the Commission has the authority, of course, to change the policy from time to time?

A (Witness Grubb) Is that -- you're asking me to --

Q Yes. I think I heard you say that. But I'm --

A (Witness Grubb) Yes, I did. The Commission has that authority. We think the 70/30 is the appropriate level. And we would not recommend changing it, but that's their ultimate decision.

Q Over half of the PPA capacity -- over half of Georgia Power's PPA capacity are actually contracts with affiliate companies, correct, like Alabama Power, Southern Power, other sister companies?

A (Witness Grubb) Well, most of it would be the Southern Power Company, but, again, those PPAs have provided great values to customers and were the winning bids in competitive solicitations.

Q Yes. You mentioned, though, that there's some reliability risks. And I know -- well, I assume you don't mean to suggest that the PPAs with your sister companies are unreliable, but I haven't heard yet what you do mean by that, when you say that there's a reliability risk to PPAs.

A (Witness Grubb) So I did mention this morning, from a reliability standpoint, while the PPAs have good performance at the end of the day they are contracts that have liquidated damages and those types of aspects. And so while we have had good performance, it's still just a contractual obligation for those counter parties, whether it be Southern Power or anybody else versus the Company's obligation to serve.

So we're going to do everything we need to on our resources to make sure they're available. PPAs could make the decision of, I don't want to winterize because that money doesn't make me perform well enough to get me enough return in the contract. So PPAs are valuable. We've got a lot of PPAs. We've had a lot of success with PPAs, but, at the end of the day, there is a difference between them.

The other thing we've mentioned again is the flexibility of an owned resource to change with the system. Whether it be, you know, recent changes like we saw from the reliability shift from summer to winter. You're having to contract for 20 years. So we're going to set requirements for combustion turbines, CCs, batteries. We're going to make it based on the latest and greatest information.

But you can't change that contract easily, or even at all, over those 20 years. Company-owned resource, you can. And then from a transmission standpoint, the system is very, very dynamic. And so a company-owned resource, you can change the operation of that resource a lot easier than a contractual resource that may not give you that flexibility. So not saying that PPAs, by themselves, totally are unreliable, it's just a different incentive for liability between a contract and ownership.

Q Do you have any examples, Mr. Grubb, when PPAs have been unable to perform for Georgia Power, as they're

contractually required to, in a way that has endangered customer load?

A (Witness Grubb) We would have to look at those. I do know the company was able to perform better with company-owned resources in Winter Storm Elliott than PPAs did. But, again, we would have to go back and look at what the outages were and those types of things. But, again, not saying that they don't ever perform, but at the end of the day, there is a different reliability responsibility.

MS. WHITFIELD: Chairman Shaw, could we make that a hearing request that they provide that PPA information?

CHAIRMAN SHAW: Yes.

MR. HEWITSON: Well, can I confirm what the hearing request is?

MS. WHITFIELD: For evidence that PPAs have been unable to perform as they're contractually required in order to meet customer load.

MR. HEWITSON: Based on what statement? Mr. Grubb said that there's a difference in reliability. I don't think he said that they're unable to perform. So I'm just trying to figure out how we respond to it. It's an allegation made, asking us to respond. If there's data that we can

provide, I mean, is there --

MS. WHITFIELD: It's not an allegation. It's a question. He said he wasn't sure. Seems pretty important if this is sort of the legal basis of your request.

MR. HEWITSON: Yeah. But I'm asking for what is the data that we would need to refer -- I mean, a hearing request is for data.

MS. WHITFIELD: Yes. For the instances, the times when PPAs have been unable to perform, as contractually required and that's endangered customer load, the company's ability to meet customer load.

VICE CHAIRMAN ECHOLS: Mr. Grubb?

MR. GRUBB: Yes, sir?

VICE CHAIRMAN ECHOLS: I seem to remember about Procter & Gamble biomass 50-megawatt facility, do you remember when that turbine went bad and they were down for a year unable to fulfill their commitment?

MR. GRUBB: I don't a hundred percent remember, but, yeah, I do know that we've had some of those, yes.

VICE CHAIRMAN ECHOLS: So that's an example of one that was down, supplying the marine base with power and steam, and they were down for more than a year?

MR. GRUBB: Right. And there's also -- it could be that it's not that they didn't deliver under the contract. It could mean that they didn't deliver, and there was a financial payment. And so that's another issue where they performed under the contract, but we didn't get megawatts.

And so when you say they failed -- that's why some of the questions are around what the hearing request is, at the end of day, they may make a decision that's, like, I'm going to take my performance penalty because I may not operate for one day in the winter, but I get a 1 percent capacity payment reduction. I'm going to be okay with that; whereas, we don't do that on the ownership side.

We have not had any instances of shedding firm load, and so there's not going to be a PPA that failed that caused -- to put the lights out, but at the end of the day, it's a payment versus megawatt hours on there. So that's what we're talking about on reliability.

VICE CHAIRMAN ECHOLS: It's just the very thing that got Texas in trouble; right? The PPAs -- I mean, those independent power producers. They didn't winterize, and they didn't perform.

MR. GRUBB: There are different incentives.

COMMISSIONER PRIDEMORE: Some would argue deregulation is where it started.

MR. JOHNSON: I would agree.

BY MS. WHITFIELD:

Q All right. I want to shift gears and talk about the Aurora modeling. May Mr. Sherrier approach with another exhibit?

CHAIRMAN SHAW: Sure.

(The document referred to was marked for identification as GIPL Exhibit 2.)

BY MS. WHITFIELD:

Q So I just want to take a look at what's been marked as GIPL Exhibit 2, and this is an Aurora modeling output in which it's reflecting the resources that your modeling system has selected as economically optimal under the various gas scenarios. We only included here three of the scenarios, medium gas, high gas, and low gas, just to save paper.

But, first of all, economically optimal, I saw that phrase used a lot, but I didn't see a definition for it. Could you tell me what that means in the context of the Aurora modeling?

A (Witness Grubb) Yeah. And so, Mr. Bush can jump in here if he needs to add any flavor to it.

But, yeah, what the Aurora model is doing,

Commissioners, this is the same model and modeling process we've had for the last several IRPs. Is it's looking at meeting our capacity requirements, most economically. So it's a production cost and a capital cost model. So it's dispatching the system, and then it's looking at years in which we have a capacity need, and looking at the cost to build different generation types, the energy value you get from those energy types, and it will evaluate thousands and thousands of situations to figure out this is the most economically optimal under those modeling conditions.

And so, for example, this MG zero is moderate gas zero carbon. It looks at dispatching the fleet up until the need of a system need year, not Georgia Power, and then it evaluates in 300-megawatt blocks. Do I add storage, do I add CTs, do I add CCs? And it knows -- it's projecting all the way out through the 35 years of the model.

So it knows if I build a combined cycle, here's what I get for 35 years. So economically optimal is building those resources to meet the needs of the system with the lowest overall cost, including fuel costs and costs to build.

Q So to understand this exhibit, it appears -- and I'm looking at the first page, which we've handwritten numbers one out of six, but it appears from this one that Aurora has selected for that moderate gas option the

Mississippi Power PPA and 900 megawatts of batteries for 2027. Am I reading that correctly?

A That's correct. And then 300 megawatts of CTs in '28 and some more batteries in '28.

Q And some more solar, as well. So before we even get to 2029, when we agree that the All-Source RFP can start providing resources, the model is selected over 1,600 megawatts, the battery storage is being economically optimal, and 750 megawatts of solar, and only 300 megawatts of CTs.

A (Witness Grubb) Yes. So Commissioners, the 750 megawatts of solar does not contribute to winter capacity, but what it's showing is there's an economic benefit of adding that solar, which we've already talked a lot today about our solar RFPs.

So what this model is showing is that to meet the needs through '28, it's a combination of CTs, batteries, and the Mississippi PPA. We did not put the specific resources in here but what this is showing is that the combination of batteries and CTs are what's optimal for resolving these needs.

And so we use that guidance, but that's not what drove the exact resources in this case. It supports them. What we did was we knew that the batteries and CTs were important resources and valuable resources through that time

period, and we're deploying them as quickly as we can.

Q So the Yates CTs, when you modeled those CTs in this resource mix plan, did you model them as gas or oil or is it -- I think I read you modeled them as a generic CT, but does that mean gas, or oil, or both?

A (Witness Grubb) So we did not model the Yates specifics in the resource mix. The resource mix was run before we completed the resource portfolio, but it supports it with the technology type. So the economic analysis on the specific resources is in the other part of the technical appendix, and so we didn't model it here. So these are generic CTs that are very comparable to Yates. They are dual fuel.

Q They're dual fuel?

A (Witness Grubb) Uh-huh.

Q Okay. And I think I heard you say, Mr. Grubb, I may have misheard you, that Yates has -- the site doesn't have firm gas for these particular CTs, but that the site had gas through the mid-30s?

A So we expect gas to be available for those CTs. Beyond that, what I was specifically referring to was, we do have firm gas for the Yates 6 and 7 units that we would be able to use in the Yates CTs, anytime we didn't need all of them. So on a winter morning when we need all of them, we're going to use the firm gas for the Yates steam units.

We would use oil for the CTs. But in other times we would actually run the Yates CTs because they're more efficient than the Yates steam units. So I was referring to Yates, the site, that has gas --

Q So --

A -- for the steam units.

Q -- to clarify, I think you were saying that the firm CT contracts for the other units at Yates expire in the '30s, but you would expect to continue those?

A (Witness Grubb) That'll be a decision we'll make down the road, but yes.

Q Okay. And the units selected for Yates are capable of running on hydrogen; correct? Some blend of hydrogen?

A (Witness Bush) Yes. The units that we'll be deploying blend 30 percent, just day one.

Q Okay. Is there any expectation or plan that that would take place in the future, that hydrogen would be used at Yates?

A (Witness Bush) Well, again, I think, like we look to all emerging technologies, if we can find the resource, an abundance of the resource, and it's an economic option, we absolutely will consider that going forward. Today, we do not see hydrogen, particularly in the volume needed to run these resources, available for us to do that.

Q Okay. Shifting gears again. I want to talk about the load forecast, and this is my last topic, Chairman Shaw.

So the load forecasting method -- I specifically want to talk about -- I understand that the traditional load forecasting method is roughly the same as it's -- or it's the same --

A (Witness Valle) Correct.

Q -- as it's been. I specifically want to talk about that extra load forecasting for the really big loads.

A (Witness Valle) Sure.

Q On page 19, line 20, you testified that the math you used or the programs that you used to account for this allow you to plan for a, quote, "Probable amount of customer choice load and avoid overestimating load additions."

Probable, to me, means more likely than not. So my question is: Is that what it means in this -- in this testimony here?

A (Witness Valle) So in this context, Commissioners, the word probable means that the range has attached a distribution of probabilities. So for every level in the range, we can tell you with certainty the load is going to be achieved or not. That's the meaning of what is it's intended to represent.

Q Okay. So here it doesn't mean more likely than not, it means a plan with probabilities, as opposed to a likely amount of customer choice load? And feel free to take a second to read it, if that's helpful.

A (Witness Grubb) Can you ask the question again? We just want to make sure we're...

Q Yeah, yeah, yeah. So I'm trying to understand, in the context of this statement, which in my view, is really important because it's the, you know -- the, sort of, heft behind this additional load.

You say that you were planning for a probable amount of customer choice load to avoid overestimating load additions. What I'm asking is: Does probable there mean more likely than not? An amount of load that is more likely than not?

A (Witness Valle) Yeah. Yeah. In this context, yeah. That's correct.

Q Okay. And so you've described, Mr. Valle, is it Valle? Valle?

A Valle.

Q Valle, okay.

You've described the process that included taking the customers who call the Georgia Department of Economic Development and decide whether they're going to come to Georgia, then decide whether they're going to go to Georgia

Power, and then decide where they're going to be sited, and how quickly they're going to build and all that, and at each stage along the way you've assigned probabilities; correct?

A Yes.

Q And I think the probability for each one of those decision points is trade secret, if I'm --

A (Witness Grubb) Correct.

Q Okay. So I won't ask about that. But then you let the math do the rest, and that's a computer program; is that right?

A (Witness Valle) It's a simulation approach, yes.

Q Okay. And so you've described that you've run that a hundred thousand times?

A (Witness Valle) Right.

Q Is it correct that I understand that to mean that when you run that a hundred thousand times, each time the computer looks at your range of probabilities and picks like, this time, yes, Georgia; this time, yes, Georgia Power; this time, they're delayed in building; and this time, they only meet 95 percent of their load, or whatever. It sort of picks options, and then picks different options a hundred thousand times to create a range of possibilities?

A (Witness Valle) That is correct.

Q Okay.

COMMISSIONER PRIDEMORE: May I just ask a quick question, because that just sparked something?

Who wrote the software? Who wrote the probability software?

MR. VALLE: So we develop it in-house.

COMMISSIONER PRIDEMORE: Okay. All right. Thank you.

BY MS. WHITFIELD:

Q So the outcome of that is information that tells you both the range of potential megawatt growth from, like, everybody says no, no one's coming to Georgia, no one picks Georgia Power, a tornado has happened and devastated the state, to, yes, everyone's coming, everyone picks Georgia Power, everyone builds on time; right? I assume your hundred thousand options get close to those end points; is that correct?

A (Witness Valle) Yes.

And, Commissioners, I would like to put some context for you to understand. It may sound like it's complicated but it's not. So the scenario that's described here whether we have to serve all of the customers in the pipeline or not, is not realistic. It's possible, but it's very unlikely that all of the customers in the pipeline are going to select to stay in our company.

Therefore, what we're trying to do with this

methodology is we're trying to grab that initial range and narrow it down to a reasonable estimate of the real value of the load that we have to -- that we have to guess. Just to give you a simple example, not really with load, let's say you have to estimate my heighth. If you were to have a tape measure, you would know that I'm 6'2.

In absence of that, you can have an educated guess and you can say, Well, it's between 5-and-a-half and 7, but that would be way too big of a range. What we're doing with this methodology is we're narrowing down the range, such as the answer is between 6'1" and 6'3" with a 90-percent confidence. And so that's the power of the methodology that we're doing.

First, we're grabbing everything that is out on the economic development pipeline. We assigned likelihoods for each one of the customers, and then, we calculate a narrow range, the more informed range that helps to create a reasonable forecast and something that informs the load that we have to serve with a confidence attached to it, and that's the probabilistic nature of the process.

Q So the projections here -- may Mr. Sherrier approach with an exhibit while I ask some more questions?

CHAIRMAN SHAW: Yes.

BY MS. WHITFIELD:

Q The projections that you're relying upon here

are using a part of that graph, there's a hundred thousand plots, that's called P95; correct?

A (Witness Valle) That is correct.

Q And P95 is a point on the graph that is -- means 95 percent of the load -- 95 percent of those hundred thousand runs are showing fewer megawatt loads, a smaller load than the number you're using?

A (Witness Valle) Correct. So it tells you that -- again, if you start with a full size of the pipeline, the 95th percentile results in less than half of the size of the pipeline. So the 95th percentile, just to clarify for the Commissioners, it doesn't mean we're taking 95 percent of everything that is out there. We're giving you a confidence level for that. And it gives you a level that gives you certainty as an upper boundary with a very reasonable level of confidence that we're going to be at that level or below.

Q So another way of stating it, then, is that 95 percent of the time, based on those 100,000 simulations, the load was smaller than the load you're asking for here?

A (Witness Valle) Correct. And that is -- that was chosen because it supports the ask that we have in front of this Commission. It accommodates for the rapid growth that we have seen throughout 2023 where different sensitivities that we did were doubled a couple of times

throughout the year. And it also accommodates for the current capacity market conditions.

A (Witness Grubb) And so, Commissioners, we -- that higher probability and that higher load level was chosen because that's what we expect the State's load growth to be. And so when we look at planning and being able to accommodate those loads, we continue to see load growth outrunning the forecast. And there's a lot more risk on the upper side than the lower side.

And so that's why we planned in that higher range. And, again, back to our point from earlier today, adding those resources and being able to accommodate that higher level of load means more opportunity to put more downward pressure on rates for customers. But the main reason we're playing into that level is because we've continued to see, as we've gone throughout these load forecast sensitivities, more risk to the load being higher than being lower.

Q So the modeling you used, it's a pretty common mathematical model, and P95 is actually one of the least likely amounts of load to occur, but the model tells you where the most likely load growth is likely to be; right? I mean, that's the whole point is that the middle of that curve is your most likely load based on your expert assumptions; correct?

A (Witness Valle) Correct. It gives you an

expectation of probability for one of the levels on the range.

Q And that is described as P50, it's the middle where half the results are below and half the results are above; is that correct?

A (Witness Valle) That is correct. But it is not the load level that we have picked to support the IRP request, given the capacity that we have seen. See, the -- given the sizes that we see in the customers, given the speed of the development, we needed to pick a level that would give a certainty to ensure that the level of reliability will be properly accounted and planned by Mr. Grubb.

A (Witness Grubb) And, again, planning for that higher level of load because of accommodating that higher level of load, puts more downward pressure on rates for all of our customers.

Q So using that P95 rate is where -- pretty close to where everybody shows up, everybody is on time, everyone picks Georgia Power. The 50, which is what this is; right? The exhibit which is marked GIPL Exhibit 3 and was just handed out, this a model of P50, the most likely load growth; correct?

A (Witness Evans) Well, I think we have to take -- clarify some of your question a little bit there.

(The document referred to was marked for identification as GIPL Exhibit 3.)

Q Yes. Sure.

A (Witness Evans) I think you said if everyone shows up and all those answers are yes, that's not correct. As Mr. Valle said earlier, there's 17,000 megawatts in the pipeline when he did his analysis, and if you looked at it today, it would be even greater than that. So that is not saying -- our request is not saying that all 17,000 megawatts shows up by any means.

Q 17 megawatts by 2029?

A (Witness Valle) No, no. We're not saying that. We are saying that that is the size of the economic development pipeline out there. We're telling this Commission that with a 95 percent certainty, the load is going to be less than half of that amount. That's what we're saying.

Q Okay. So let's look at the most likely scenario, P50, and this is GIPL --

A (Witness Grubb) We don't agree that P50 is most likely.

Q No?

A (Witness Grubb) We would agree that, statistically, in that range, half the cases are above it -- or half are below it, but what we've been saying is, we're

looking at that higher level because we expect that to be the forecast for the State.

A (Witness Evans) And the reason for that is the pipeline, as Mr. Valle looked at it, assumed no projects that we did not have a line of sight on, at that point, would come on. We know that's not true. That's already happened. We've seen new projects come into the pipeline. So essentially what that's saying is that no growth will happen that we don't know about today. That's unrealistic.

Q So, again, we're looking -- for the purpose of this IRP update, we're looking -- basically in the next three years, right, Mr. Grubb has repeatedly said that today.

A (Witness Grubb) To add resources to meet those needs, yes.

Q Mr. Valle, I'm curious about your perspective. You sound like you're the mathematical modeler. Would you agree that P50 is representative of the most likely scenario in the model?

A (Witness Valle) From a statistical perspective, yes, I agree that the P50 level represents the median of the range of all the potential out comes. But for the purposes of this IRP, we're picking a higher level degree to represent the increases in the load that we have seen throughout 2023 and because it's a better level to plan

our -- for our resources.

Q Okay. So GIPL Exhibit 3, which is now in front of you, is the company's response to staff request DEA-1-5, it's attachment B, but it's only the top portion of Exhibit B which is then blown up into two pages just to make it possible to read.

Based on this, this is modeling of the P50 forecast; correct?

A (Witness Grubb) Yes. This is a resource and load balance at a winter P50; that's correct.

Q Okay. And based on P50 in 2026, so 2024, 2025 and 2026, Georgia Power has enough energy online -- enough capacity, sorry, online to be above a 26 percent reserve margin; correct?

A (Witness Grubb) That is correct, at these load forecasts. But, again, as we've seen the load forecast -- or the growth in the state continue to grow, that is not what we should plan for. What we need to plan for is the more probable case which is higher.

I will add, though, while we're on this, Commissioners, when we've talked about this lower level of load that we're being asked about here, when we've talked about the analysis where we put downward pressure on rates, we looked at the revenue requirements from all the resources in this plan based on serving that P95 as we're talking

about that higher load level. The revenues that we looked at were from this lower level of load, and it still showed downward pressure on rates.

So we absolutely believe the higher load forecast is the one we should plan to because of seeing growth in the state. So if we were to push back and use this load and not add resources, we would likely be having to turn customers away from choosing the State of Georgia.

Q And 2027, based on currently existing resources, Georgia Power would still be able to meet the needs of customers and have a 20 percent reserve margin roughly; correct?

A (Witness Grubb) Well, we wouldn't have a 20 percent reserve margin. We would bring forward to this Commission resources to get us to the '26. But, yes, you would have resources above target through the winter of '26. But, again, that's on this load forecast which is not the load forecast we should plan to benefit all customers. I think I cut you off, too.

A (Witness Evans) I think you said what I was going to say.

A (Witness Grubb) Okay. Sorry.

Q One more thing I need to point out about this. This chart that we're looking at, GIPL Exhibit 3, P50, those numbers were at 20 percent of -- we have a 20 percent

reserve margin in 2027. That's still not accounting for the 50 megawatts of batteries that are going to be procured through that RFP; correct? These numbers, the chart?

A (Witness Grubb) Let me -- we included those in some. Let me go make sure.

Q It's one of these notes, but it's spread over two pages.

A (Witness Grubb) Yes. I think we removed those just to show the amount that we need to procure. But, yeah, you would have the 500 megawatts batteries in there. Again, we've still got to go and procure those. So sometimes we show them in there, and sometimes we don't. But, yeah, I can't remember -- I'd have to look. I've got all the detail, but it may take me a minute or two.

Q If you take a look at Note C, it says that the capacity does not include the 500 megawatts from the already-approved RFP for batteries?

A (Witness Grubb) Yes, that's correct. It does not include them, because, again, we're trying -- that's a mechanism on which we will meet these needs, but we wanted to just reflect the needs that we're meeting through this IRP update and the RFP in the All-Source.

MS. WHITFIELD: Okay. Thank you, gentlemen. That's all I have.

CHAIRMAN SHAW: Thank you, Ms. Whitfield.

I don't think the next two are here, but I'm going to -- Georgia Solar Energy Association?

(No response.)

CHAIRMAN SHAW: Georgia One.

(No response.)

CHAIRMAN SHAW: Georgia Watch.

MS. COYLE: Good evening, again, Commissioners. Liz Coyle for Georgia Watch. Nice to see you all again. And given the hour and we want to get home before bad weather, I'm going to keep my cross very brief.

CROSS-EXAMINATION

BY MS. COYLE:

Q So, Mr. Grubb, you testified earlier, actually several times, I believe, that no revenue requirements to meet the capacity needs in this interim IRP are expected to increase rates in the 2025 rate case; is that correct?

A (Witness Grubb) When compared to the revenues of the loads they're serving, that's correct.

Q And you said that they should actually put downward pressure on rates for all customers; is that right?

A (Witness Grubb) That's right. That's correct.

Q So do you expect to file for an overall rate decrease in 2025?

A (Witness Grubb) So we can't speak to the

overall rate case. From this filing and the resources and loads in this filing, we do not expect to ask for a rate increase. But, as this Commission knows, there's a lot of other moving pieces to it.

Q So I guess you can't quantify a percentage increase or decrease at this point?

A (Witness Grubb) Not at this point. But, again, this filing is not going to put upward pressure on rates, but there's a lot of other moving factors.

Q But that statement is a defendable, absolute statement that this filing will not put upward pressure on rates in 2025?

A Based on everything we expect and what we've provided, that is correct.

Q And do you expect residential customers to be required to pay for any of the costs associated with meeting the capacity needs in this interim IRP?

A (Witness Grubb) So that's obviously part of the rate case. But resources are shared by all customer classes; right? So we don't parse out the resources to different classes. So, in the next rate case, all the costs and all the revenues would go in there. So the residential would pay for the costs for the whole system. But, again, we expect a lot more revenues to help lower those rates than we would otherwise.

Q Are you building the capacity needed in the short term because of the unexpected needs to meet residential customer needs or to meet the needs of data centers and manufacturers?

A (Witness Grubb) So, incrementally, it's those loads that are added, but we need the resources to serve all the customers forecasted. So we look at the load, we look at serving all the load. The incremental change is from those drivers, but all resources that are currently online serving customers will serve these new customers plus these new ones. And so it all is one big bucket of revenue requirements and revenues in the rate case. So these resources are serving everybody and revenues will assist everybody, as well.

A (Witness Evans) And, of course, that will show up through the cost of service study and the revenues that come in and projected in the rate case and show the parity by rate and rate group, as we've always done, and then provide information for policy decisions of how to allocate the rate increase or decrease, at that time, as we've always done.

Q So let me just ask it this way: Do you expect residential customers to subsidize providing the median capacity needs of these new manufacturers and data centers coming into the state? Are residential customers going to

be subsidizing those other customer classes?

A (Witness Grubb) No. And so what I just answered, these resources aren't specifically for the new loads, but the new loads will help pay for the resources that are serving all the customers now, so...

Q And am I correct that this interim IRP is based on both some known and some expected new growth; right?

A (Witness Grubb) That's correct.

Q So, at this point, given how close we are now to 2025, do you anticipate seeking significantly more additional capacity in the 2025 IRP?

A (Witness Grubb) For these years, we don't. This plan gets us close to that in '28. We've mentioned the flex-up option if something changes between then. But, no, the '25 IRP would be mostly focused on -- beyond there. But if we -- again, this resource plan meets the needs through '28, that flex capacity is there in case we have another update before our IRP in '25.

MS. COYLE: Thank you.

CHAIRMAN SHAW: Thank you, Ms. Coyle.

With that, we've made it through the first sheet. And if we stop now, I think everybody can get on the road and be safe. So we're going to stop here and start back in the morning at 9:30, and everybody be safe going home.

Panel, thank you.

THE PANEL: Thank you.

CHAIRMAN SHAW: So we're adjourned.

(Hearing adjourned at 5:28 p.m.)

C E R T I F I C A T E

We, Kelley Marie Nadotti, Debbie A. Eickhoff, and Brenda P. Elwell, Certified Court Reporters, do hereby certify that the foregoing transcript is an accurate record of the proceedings had in the above-entitled matter at the time and place therein set forth.



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5090-9084-2699-3664

BEFORE THE GEORGIA PUBLIC SERVICE COMMISSION

STATE OF GEORGIA

In Re:

Georgia Power Company's 2023 Integrated Resource Plan Update) Docket No. 55378

Hearing Room 110
244 Washington Street
Atlanta, Georgia

Wednesday, January 17, 2024

The above-entitled matter came on for hearing pursuant to Notice at 9:30 a.m.

PRESENT WERE:

JASON SHAW, Chairman
TIM ECHOLS, Vice-Chairman
FITZ JOHNSON, Commissioner
LAUREN "BUBBA" MCDONALD, Commissioner
TRICIA PRIDEMORE, Commissioner

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By Ms. Scott		427		
By Mr. Baker		440		
By Ms. Ariza		507		
By Mr. Jacob		526		
By Mr. Mahan		558		
By Mr. McNutt		605		
By Mr. Eaton		632		
By Mr. Hewitson			656	

P R O C E E D I N G S

CHAIRMAN SHAW: Good morning. As I remind myself to mute my phone, I'll remind everyone else to do the same, please.

This is Docket No. 55378. It's January 17th, 2024. Georgia Power Company's 2023 Integrated Resource Plan Update.

We'll start by calling for appearances. Georgia Public Service Commission.

MR. THOMAS: Preston Thomas and Ginny Davis on behalf of Public Interest Advocacy staff.

CHAIRMAN SHAW: Georgia Power Company.

MR. HEWITSON: Steve Hewitson, Brandon Marzo, Allison Prior on behalf of Georgia Power Company.

CHAIRMAN SHAW: Advanced Power Alliance.

MR. TURNER: Okay. Noah Turner, along with Brad Carver, representing Advanced Power Alliance.

CHAIRMAN SHAW: Clean Energy Buyers Association.

MR. DUNBAR: Good morning. Scott Dunbar with the law firm of Keyes & Fox here on behalf of the Clean Energy Buyers Association.

CHAIRMAN SHAW: Heelstone Renewable Energy.

MR. GALLOWAY: Good morning. Newton Galloway, Terri Lyndall on behalf of Heelstone. Thank you.

CHAIRMAN SHAW: Georgia Association of Manufacturers.

(No response.)

CHAIRMAN SHAW: Georgia Center for Energy Solutions.

(No response.)

CHAIRMAN SHAW: Georgia Coalition of Local Governments.

MS. BROWN: Good morning, Mr. Chairman. Alicia Brown on behalf of Coalition of Local Governments.

CHAIRMAN SHAW: Georgia Interfaith Power & Light.

MR. SHERRIER: Good morning. Bob Sherrier Jennifer Whitfield on behalf of Georgia Interfaith Power & Light. Thank you.

CHAIRMAN SHAW: Georgia Solar Energy Association.

(No response.)

CHAIRMAN SHAW: Georgia WAND Education Fund.

MS. SCOTT: Kimberly Scott on behalf of Georgia WAND Education Fund, Inc. Thank you.

CHAIRMAN SHAW: Good morning.

MS. SCOTT: Good morning.

CHAIRMAN SHAW: Georgia Watch.

MS. COYLE: Good morning. Liz Coyle on behalf

of Georgia Watch.

CHAIRMAN SHAW: MARTA.

MS. STURM: Good morning. Kasey Sturm on behalf of MARTA.

CHAIRMAN SHAW: Microsoft.

(No response.)

CHAIRMAN SHAW: Resource Supply Management.

MR. BAKER: Good morning, Mr. Chairman. Robert Baker on behalf of Resource Supply Management.

CHAIRMAN SHAW: Sierra Club.

MS. ARIZA: Good morning. Isabella Ariza and Curt Thompson on behalf of Sierra Club.

CHAIRMAN SHAW: Southern Alliance for Clean Energy.

MR. JACOB: Good morning. Brian Jacob for Southern Alliance for Clean Energy.

CHAIRMAN SHAW: Southern Renewable Energy Association.

MR. MAHAN: Good morning, Commissioners. Simon Mahan on behalf of the Southern Renewable Energy Association.

CHAIRMAN SHAW: Good morning.

United States Department of Defense.

MR. McNUTT: Good morning, Mr. Chairman. John McNutt on behalf of the United States Department of

Defense.

CHAIRMAN SHAW: Walmart.

MS. EATON: Good morning, Mr. Chairman. Stephanie Eaton here on behalf of Walmart, Inc. from the law firm of Spilman, Thomas & Battle. Thank you.

CHAIRMAN SHAW: Thank you.

Are there any housekeeping matters to take up before we get started today?

(No response.)

CHAIRMAN SHAW: Okay. We'll start by calling public witnesses. We have a sign-up sheet. We'll start with Ashleigh Ewald.

And if I say this wrong, just please correct me.

MS. EWALD: Hi. Thank you so much. That was right.

Hi. Sorry. Hello. My name is Ashleigh Ewald and I am student body president of Oglethorpe University. Yesterday students spoke about how it is documented that over 35 years ago Southern Company and others started to pour millions of dollars into combating the going public, political, and scientific concern about greenhouse gas emissions. They backed misleading campaigns to

attack climate science, opposed fighting limits on greenhouse gas emissions, promoted a clean coal as a false solution to the problem, and fought to slow the transition to clean and renewable energy sources like wind and solar power.

Just imagine what the world would be like today if 35 years ago those large influential business entities hadn't chose to spend millions of dollars to spread climate misinformation and they hadn't tried to convince the public and politicians across the world not to take climate action. Imagine, if instead, they had supported growing polls for climate action and taken meaningful steps to curb their significant greenhouse gas emissions.

There wouldn't have been billions of dollars of subsidies going every year to help build fossil fuel infrastructure and fund research for new polluting water-intensive technology, such as fracking. These subsidies would have gone toward clean and renewable energy instead.

Transmission lines to carry renewable energy would have been laid years and years ago when land was cheaper and there was less property to negotiate around. Clean energy technology for solar panels, wind turbines, and battery storage would have

developed sooner, reached competitive cost points sooner, and progressed way beyond where they are today. And the same would be true for energy efficiency products, such as heat pumps, improved insulation, and electric cars.

The world would be more stable as tyrants, such as Vladamir Putin, would not have amassed such great wealth and power through exploiting their country's oil and gas resources. Countries without oil and gas resources would have developed their infrastructure to use the wind and solar that many of them have in plentiful amounts. This would have created more prosperity and stability in those countries. And when combined with less climate-fueled droughts and flooding, there would be so many fewer people migrating from their homes to other countries in order to survive.

Our air and water would be cleaner. There would be less cancer, less asthma, and less black lung disease. But this is not the world we live in today because people who benefit from fossil fuels use their power and influence to stop and stall climate action. They chose profits over people and our planet.

Thank you.

CHAIRMAN SHAW: Thank you.

COMMISSIONER PRIDEMORE: Ms. Ewald -- excuse me, Ms. Ewald.

MS. EWALD: Yes.

COMMISSIONER PRIDEMORE: Can I ask you a question? Did you receive class credit for coming in today?

MS. EWALD: Ma'am, no. This was actually voluntary.

COMMISSIONER PRIDEMORE: It was volunteer. Were you asked by a professor or by a member of the faculty at Oglethorpe to come today?

MS. EWALD: No, ma'am.

COMMISSIONER PRIDEMORE: Thank you.

MS. EWALD: Thank you so much. Have a great one.

CHAIRMAN SHAW: Okay. Next is Jenifer Nguyen. Good morning.

MS. NGUYEN: Good morning. My name is Jenifer Nguyen and I am a student and alumna of Georgia State University. Yesterday, student speakers talked about the benefits of rooftop solar for our state. We will email you a document containing those comments, as well as all other student comments made yesterday and today. The documents

will contain footnotes leading to all sources referenced.

But for now, to sum up the situation, Georgia Power is acting -- asking to purchase more natural gas and to build more natural gas infrastructure to meet anticipated future peak demand. This is something that climate scientists are explicitly saying we cannot do if we want to meet critical climate targets and prevent dramatically worse climate impacts.

And Georgia Power is actively resisting expanding the RNR net metering program, even though this expansion would reduce the peak demand and would bring so many economic and health benefits to people in our state. Net metering policies that credit excess electricity at the retail rate is something that 33 states have already done and that almost all 33 states are still doing.

This is not a situation where it is appropriate to find a compromise position between what Georgia Power wants and what intervenors have been requesting since the pilot's RNR net metering program reached its cap in 2021.

This is a good point to answer Commission Echols' question from yesterday. We didn't get a

chance to consult with experts on this matter, but we believe that 295,000 homes with 10-kilowatt solar arrays would generate up to 2,950 megawatts of electricity during peak summer hours. This is a significant amount of energy.

CHAIRMAN SHAW: How much did you say? 2,950; not 295 megawatts?

MS. NGUYEN: No. 2,950 megawatts. 2,950.

CHAIRMAN SHAW: Are you sure?

MS. NGUYEN: 2,950.

COMMISSIONER SHAW: Wow.

MS. NGUYEN: The math was done.

VICE-CHAIRMAN ECHOLS: Thank you for that.

MS. NGUYEN: So Georgia Power has come back to you outside of regular -- outside of the regular IRP cycle because they now anticipate a need for additional energy that is 17 times what they projected during the regular 2022 proceedings.

Please act now to require Georgia Power to reinstate RNR monthly net metering without a cap in response to this additional predicted energy need.

Thank you.

CHAIRMAN SHAW: Thank you.

COMMISSIONER PRIDEMORE: Ms. Nguyen?

MS. NGUYEN: Yes.

COMMISSIONER PRIDEMORE: Did you receive class credit or course credit for coming in today?

MS. NGUYEN: Absolutely not. I am actually pursuing a computer science degree.

COMMISSIONER PRIDEMORE: Oh, nice.

Were you encouraged by faculty or a member of the staff --

MS. NGUYEN: No.

COMMISSIONER PRIDEMORE: -- at Georgia State to come in today?

MS. NGUYEN: Absolutely not.

COMMISSIONER PRIDEMORE: Do you represent a group -- a student group?

And, if so, what's the name of the group?

MS. NGUYEN: Yes. The Student Environmental Team of Georgia State University.

COMMISSIONER PRIDEMORE: Student Environmental --

MS. NGUYEN: Team.

COMMISSIONER PRIDEMORE: Team, okay.

All right. Thanks, Ms. Nguyen. Have a good day.

CHAIRMAN SHAW: Thank you.

Jovan Downs.

MS. DOWNS: Good morning. My name is Jovan

Downs and I'm an 11th grader at Decatur High School.

Georgia Power must also invest in offshore wind turbines. Offshore wind is a great complement to solar by generating power during the times when sunlight is absent or weaker. The National Renewable Energy Laboratory, NREL, has determined that Virginia, North Carolina, South Carolina, and Georgia have distinct resource quality advantages for offshore wind generation. Together, they have 82 percent of the East Coast resource in shallow water making it possible to get further offshore. And the proximity of warm water, Gulf Stream of the coast, creates a highly energetic microclimate with higher wind speeds.

According to Jennette Gayer, Director of the Environmental Georgia Research and Policy Center: We have an enormous renewable resource blowing just off our coastline that can help close the gap between us and a 100-percent renewable energy future.

The Center's April 2021 report found that Georgia could provide more than enough electricity to meet its 2019 electricity demand and over half of what it's projected to use in 2050 with offshore wind.

Virgina and North Carolina recently entered into an agreement to work together on offshore wind development. Karen Green with the Center for a Sustainable Coast has the comment: Over a decade ago, a feasible study identified two suitable sites for wind farms off the cost of Georgia. Since then, the climate crisis has grown ever more urgent.

What are we waiting for? It is critical that Georgia Power meets its increasing energy demands with clean, renewable energy. We must take advantage of our offshore wind potential. It is critical that Georgia Power meets its increasing energy demands with clean, renewable energy. We must take advantage of our offshore wind potential.

Please act now to direct Georgia Power to coordinate with Governor Kemp and Georgia legislature to work together on offshore wind development. We must act now. Later is too late.

Thank you.

CHAIRMAN SHAW: Thank you.

COMMISSIONER PRIDEMORE: Thank you, Ms. Downs. Can I ask you a question?

MS. DOWNS: Yes.

COMMISSIONER PRIDEMORE: Or a couple of questions.

Were you given class or course credit from Decatur High to come today?

MS. DOWNS: No, I was not.

COMMISSIONER PRIDEMORE: Okay. Were you encouraged by a member of the faculty or the staff?

MS. DOWNS: No, I was not.

COMMISSIONER PRIDEMORE: Are you part of a group at Decatur High School that studies or works on these issues?

MS. DOWNS: No, I am not.

COMMISSIONER PRIDEMORE: All right. Thank you.

COMMISSONER McDONALD: Have you studied the offshore winds in New England?

MS. DOWNS: Have I personally?

COMMISSONER McDONALD: The project of the turbines that have been built out there and they pulled the plug on them?

MS. DOWNS: No, I have not.

COMMISSONER McDONALD: You should.

MS. DOWNS: I will. Thank you.

VICE-CHAIRMAN ECHOLS: Have you ever been to Tybee Island?

MS. DOWNS: Yes, I have.

COMMISSIONER JOHNSON: They're not going to let you go.

VICE-CHAIRMAN ECHOLS: Back in 2012, Tybee was donated a wind turbine that they were going to put at the wastewater treatment plant onshore, but DNR came in with a migratory bird study that basically scared all the councilmen down there. And they voted against putting up this free wind turbine that was going to provide a lot of power because of the migratory bird study. You might want to look that up.

MS. DOWNS: All right. Thank you.

COMMISSIONER JOHNSON: I -- just kidding.

CHAIRMAN SHAW: Thank you for coming.

Benjamin Hastie.

MR. HASTIE: Hello.

CHAIRMAN SHAW: Good morning.

MR. HASTIE: Sorry.

CHAIRMAN SHAW: Good morning.

MR. HASTIE: Good morning. Hello. My name is Benjamin Hastie and I am a junior at Decatur High School.

The Edison Electric Institute, an association that represents all U.S. investor-owned electric companies, has already created a very informative booklet presenting over 100 small and large ways for customers to reduce energy consumption. But these

are presented in the context of saving money, not in the context of helping to save the planet and its inhabitants.

Georgians should be told that reducing their energy consumption and changing some of their main consumption to off-peak hours would help prevent the need to invest in more fossil fuel plants and fossil fuel energy sources. And they should be informed that this is a critical component of meeting international greenhouse gas emission reduction targets in the timeframe that will help eliminate even more dangerous levels of global warming.

This message can easily be sent in print and/or digital form to schools to reach students and parents, to neighborhood associations and churches to reach people within their communities, to businesses and offices. And we have reached out to instructors at the Savannah School of Art and Design to see if they would be willing to help create video messaging. They have responded that they would be excited and honored to participate in such an important effort.

Georgia Power should also increase incentives for people who successfully limit their energy consumption, provide more rebates for those who

purchase energy-saving devices, and provide more funding for programs that help elderly and low-income customers insulate their homes.

Please act now to require Georgia Power to invest more heavily in demand-side management, educating Georgia citizens about our climate emergency and how, together, we can take action to help to prevent global warming. We must act now. Later is too late.

Thank you.

CHAIRMAN SHAW: Thank you.

COMMISSIONER PRIDEMORE: Mr. Hastie, hi. Good morning.

MR. HASTIE: Sorry.

COMMISSIONER PRIDEMORE: Good morning.

Did you receive class or course credit for coming today?

MR. HASTIE: No, I did not.

COMMISSIONER PRIDEMORE: Were you encouraged by a member of the faculty or staff?

MR. HASTIE: I was not.

COMMISSIONER PRIDEMORE: Okay. Are you a part of a student group that studies these issues?

MR. HASTIE: No, I am not.

COMMISSIONER PRIDEMORE: Okay. Nice to meet

you.

MR. HASTIE: Nice to meet you, too.

VICE-CHAIRMAN ECHOLS: Hey, I think you-all should receive some class credit, really. I mean, it's a great -- not many high-school kids venture here. You know, an opportunity to speak. I know it's -- it's a brave thing.

So, you know, tell your -- tell your teacher: Hey, Commissioner Echols said we should be getting credit.

MR. HASTIE: Thank you. I will.

COMMISSONER McDONALD: And it wasn't warm when I left this morning.

CHAIRMAN SHAW: Yeah. You-all got up on a cold morning to come, too.

MR. HASTIE: Thank you.

CHAIRMAN SHAW: Thank you.

Evelyn Ford.

MS. BROCK: Excuse me. Is the list in order? I'm sorry. I'm -- there may be somebody ahead of me. I was supposed to go after Jovan Downs.

COMMISSONER McDONALD: We can't hear you.

CHAIRMAN SHAW: Okay. What is -- what is your name?

MS. BROCK: Kathryn Brock.

CHAIRMAN SHAW: Oh, okay. Well, come on up.

MS. BROCK: Okay.

CHAIRMAN SHAW: I'm sorry.

MS. BROCK: No worries.

Hello, my name is Kathryn Brock. I'm a student at Decatur High School.

Georgia Power must also invest more heavily in demand-side management presenting opportunities for reducing energy consumption in the context and scope of the global climate crisis.

Climate disinformation has robbed people of the opportunity to take critical action to protect themselves, their loved ones, and their future generations. When presented with correct information and action, Georgians will respond.

Will this really work? Yes. Absolutely. As long as the information is clear, consistent, widespread and repeated.

Let's take the example of World War II when people were asked -- were called upon to take action and make sacrifices for their future. They planted victory gardens, they collected scrap metals, they rationed -- they recycled rags, paper, silk, and string. They supported government efforts to make big changes quickly.

Existing industries were converted into wartime production and huge factories were built to produce supplies for those fighting abroad. People at home supported government rationing for so many basic items, like sugar, meat, and coffee. They also supported raising corporate taxes in both corporate and personal income. They are known as the greatest generation for their action and their sacrifices.

Today, the scientific community is calling upon all of us to make big changes to address the biggest threat facing humanity today. They are saying that the entire global community must act immediately to prevent warming levels that will reach tipping points that will greatly escalate death, disease, and global instability. Scientists are telling us that the actions that we take today will impact the world for hundreds, perhaps thousands of years.

It's a pretty safe bet that we can rise to the occasion, that we will make the changes needed and form new habits, and collectively become the next greatest generation. With regards to reducing electricity consumption, most of the changes we must personally make won't even require a great amount of effort and they will save us money, be better for our health, and lead to cleaner air and water. But

people will only act if they understand the urgency of our present circumstances. And Georgia Power must play a central role in communicating this urgency.

Thank you.

CHAIRMAN SHAW: Thank you, Ms. Brock.

COMMISSIONER PRIDEMORE: Ms. Brock, you go to Decatur High?

MS. BROCK: Yes, ma'am.

COMMISSIONER PRIDEMORE: Okay. Let me just ask you a question. Are you marked absent for not being there today?

MS. BROCK: So we had a two-hour delay this morning. So I won't be marked absent, but I will probably be tardy.

COMMISSIONER PRIDEMORE: You'll be tardy.

Okay. If you need a note, our executive secretary, she'll get you guys notes to get you --

MS. BROCK: Thank you. I appreciate that.

COMMISSIONER PRIDEMORE: -- notes for coming down here.

Were you solicited to come down here by an intervenor in this case?

MS. BROCK: No, ma'am.

COMMISSIONER PRIDEMORE: Okay. Are you being

paid for being present today?

MS. BROCK: No, ma'am.

COMMISSIONER PRIDEMORE: All right. There you go. Nice to meet you. Thank you.

MS. BROCK: Thank you. Nice to meet you, as well.

CHAIRMAN SHAW: Okay. Let me get back on track here. Evelyn Ford.

Good morning.

MS. FORD: Good morning. Hello, my name is Evelyn Ford and I'm a senior at Decatur High School.

Since we were little, we were taught to pick up after ourselves and to clean up our messes. But in its latest IRP request, Georgia Power is definitely not taking action to help clean up this huge climate mess that they have helped to create.

They are acting as if it is business as usual. Maybe they'll start taking responsibility soon due to regulation and policy that requires them to do so, stockholder and public pressure, or even because of an attack on conscience.

But the scientific community is clear, we must take rapid action now. That includes both Georgia Power and Georgia citizens because later is too late. You can help get Georgia Power to take the

right actions in the essential timeframe. Actually, you're the only five people in Georgia who can.

Cities and counties across the state are committing to reach zero greenhouse gas emissions by 2050, investing money and energy to do so. But they don't have the authority to make Georgia Power provide them with the clean energy that is -- or clean electricity that is essential for reaching these goals, but you do.

The five of you are in positions of incredible responsibility, power, and opportunity, as I'm sure you know. But -- but Georgia Power -- under your direction, Georgia Power can become a shining example.

Commissioner Pridemore, your new position as President of the National Association of Regulatory Utility Commissioners, you will have the opportunity to use your influence to encourage other regulators and utilities to follow Georgia Power's lead.

Georgia Power wants you to believe that they have no choice, that they must increase natural gas sourcing and infrastructure and potentially keep coal plants running for longer in order to keep the lights on. But this is simply false. There are many choices they can make when sourcing our

electricity that will keep the power on.

The choices Georgia Power is presenting now may be the easiest, given their current business model. They may be the most profitable for their company, but they are definitely not the best choices for Georgia's economy and the safety of its people, especially the younger generations who will be dealing with the consequences of those choices for most of their lives -- most of our lives.

We aren't here today as experts versed in the climate sciences and solutions. We are here to point you to the experts. We are asking that you listen to the worldwide scientific community that is sending out both calls to action and proper solutions.

Georgia Power -- Georgia Power's failure to align their policies and practices with what the science shows is a colossal dereliction of duty and mounting liability risks. Please, fulfill your duty. Act to keep us safe.

Exercise your authority to require Georgia Power to make heavy investments in clean, renewable energy, battery storage, and demand-side management, not in additional fossil fuels that will only make the problem worse. You must act now. Later is too

late.

Thank you.

CHAIRMAN SHAW: Thank you.

COMMISSIONER PRIDEMORE: Hi, ma'am, how are you?

MS. FORD: Good. How are you?

COMMISSIONER PRIDEMORE: Good.

Are you being paid for being present today?

MS. FORD: I am not being paid.

COMMISSIONER PRIDEMORE: Okay. Were you asked to be here by any of the intervenors in this case?

MS. FORD: I was not, no.

COMMISSIONER PRIDEMORE: Thank you.

MS. FORD: Thank you.

VICE-CHAIRMAN ECHOLS: Can I ask you a question?

MS. FORD: Yes.

VICE-CHAIRMAN ECHOLS: I've been trying to get the Decatur school system to get some electric buses because their routes are small; right?

MS. FORD: Yes, they are. Four square miles.

VICE-CHAIRMAN ECHOLS: I've been unsuccessful at getting your superintendent and leadership to -- to look at this.

Could you go back and maybe write a little

speech and go over there to the superintendent, you know, maybe at the next Board meeting and talk about how the City of Decatur can play a key role in all the things that you're talking about by implementing an electric school bus program?

Would you do that for me?

MS. FORD: Yeah. For sure.

VICE-CHAIRMAN ECHOLS: Great. Thank you.

MS. FORD: As someone who rides the bus every single day.

COMMISSONER McDONALD: They can't use them in Chicago this morning.

VICE-CHAIRMAN ECHOLS: No. No, they can't.

CHAIRMAN SHAW: All right. Tim Franzen.

Good morning.

MR. FRANZEN: Good morning. I'm a sophomore at Decatur High.

VICE-CHAIRMAN ECHOLS: You look like you're heading to Chicago after this.

MR. FRANZEN: I do want to say I've never met any of these young people. I didn't encourage them to be here. But no one, more than y'all, have a stake here. I mean, the decisions made today affect y'all more than me and more than any of y'all. So I'm really grateful that y'all are here.

And, also, I was thinking, man, if I had two hours before high school, this is the last place I'd be coming. And I just wanted to echo the sentiment. I don't want to get into the weeds.

But, you know, what I hear y'all asking for is a way to expand Georgia's energy needs without destroying the climate. And that's, like, at the heart of what I'm hearing from y'all.

And so I'm not going to get into the weeds either. I just want to echo those -- those sentiments.

My name, again, is Tim Franzen. I'm with the American Friends Service Committee. We have a small presence in Atlanta, but as an organization we've been around for over a hundred years. We're one of three Nobel Laureate organizations here in Atlanta, along with the Carter Center and the King Center.

And what brought me here, in addition to the concerns that the young folks spoke about, is that, you know, Georgia Power and the Southern Company -- I'm concerned that profits are being used to influence politics more than they should be.

You know, we're continuing to invest in a system that's killing us. And to know that there are dollars going into lobby, to know that there's

money going into controversial democracy-crushing programs like Cop City, like $2 million, and you see Georgia Company listed on community fundraisers, is a slap in the face to the folks that are experiencing the potential of rate increases.

And so, you know, I just want to echo the sentiments of young folks and encourage this body to put some checks and balances. This is our future. It's your future more than ours.

And thank you for having me. I give my one minute back.

CHAIRMAN SHAW: Thank you, sir.

That -- that's -- that's all I had on the sign-up sheet. Was there anyone else that came in later that wanted to comment?

COMMISSONER McDONALD: Mr. Hewiston, do you have any redirect?

MR. HEWISTON: I would love to, Mr. Commissioner, but I don't think that's proper at this time.

CHAIRMAN SHAW: All right. We're going to end it.

Thank you-all again to everyone that came down as public witnesses, especially the students. We appreciate y'all's engagement and good luck in the

rest of the school year. Be safe getting back to school today.

COMMISSIONER JOHNSON: Get that note.

CHAIRMAN SHAW: I see the panel coming in. So we're going to -- if there is anyone that needs to leave, this would be a -- you know, a good time, but I'm not trying to tell you to leave. Leave when you want, but we're just kind of setting things back up real quick.

We'll pick up where we left off yesterday since this is the second day of the hearing. I'll remind everyone to please try to refrain from asking questions that have already been answered on the first day.

So Ms. Scott was not able to be here yesterday, but did you have some cross?

MS. SCOTT: I do.

CHAIRMAN SHAW: You do?

Okay. I'll start with you then because we went by you yesterday.

MS. SCOTT: Thank you.

CHAIRMAN SHAW: Good morning, panel.

MR. GRUBB: Good morning.

MR. VALLE: Good morning.

MR. BUSH: Good morning.

MR. EVANS: Good morning.

CHAIRMAN SHAW: Are you guys just about ready to go?

MR. GRUBB: Yes, sir.

CHAIRMAN SHAW: I just want to remind you that you're still under oath.

MR. GRUBB: Yes, sir.

CHAIRMAN SHAW: All right. I'm going to call on Georgia WAND to come up at this time.

Good morning.

MS. SCOTT: Good morning, Commissioner Shaw, the rest of the Public Service Commissioners.

CROSS-EXAMINATION

BY MS. SCOTT:

Q My name is Kim Scott. I'm with Georgia WAND. And thank you for the opportunity to be able to cross-examine. I was caught up in traffic -- I mean, not traffic -- but my flight was delayed yesterday from Kansas City. So we talk about negative 26 degree temps, that's where I came from. So thank you for the opportunity to provide this cross-examination.

But I was listening on YouTube and I heard a lot of questions about downward pressure on rates. So that would be my first question. Can you explain downward pressure on rates?

A (Witness Grubb) Yes. So it's because you're going to have an increased load growth, it's a larger customer base in which to spread the cost of the system to serve those customers.

Q And then in yesterday's hearing we heard a lot about our capacity and we didn't need the capacity right now that is being entertained in this IRP.

So why are we entertaining increasing the capacity in this IRP, instead of the 2025?

A (Witness Grubb) So that -- I don't recall us saying we didn't need it. The opposite is actually true. We do need it now.

And so if we wait until the '25 IRP, we do not have time to deploy resources to meet the needs by the end of '25, into '26, and into '27.

Q And you also talked about flaws in your forecasting method that we've seen. Basically, it's requiring 1,600 percent greater demand than the flawed model that you used in 2022's IRP. So you -- you talked about a new forecasting model, which we would appreciate, but why is it better than the old one?

And then would it -- would it put us in the right direction going forward?

And then the other part of that question is, is that: Are there utilities that are using it now that we

can reference and how long has this model been used --

A (Witness Grubb) Yeah, so, first off, the -- Commissioner, the IRP load forecasts are not flawed and the method is not flawed. The '22 IRP load forecast was based on the information at that time that we knew and the processes and models that we've been using with this Commission for years. So it was not flawed.

What has happened is the economic growth in the state has changed and so we've updated that load forecast. So nothing was flawed in '22 or '23 before we rolled into this year. So what we've had to do is have some new aspects to the large-load external adjustments. But, again, external adjustments have been part of the load forecast.

So I'll let Mr. Valle speak to a little bit of that. But, again, it was not flawed. The '22 IRP load graph forecast was approved and reviewed in the '22 IRP. It's just been a generational change since then with load.

So Mr. Valle can speak to the -- the current method on how we're handling the external adjustments.

A (Witness Valle) Yeah. Thank you, Mr. Grubb. So I -- before -- before I get there, I want to reiterate what I said yesterday. The methodologies that we are using are the same methodologies that we have been using

in previous years and it's been -- it's been serving the planning purposes of our customers really well.

The only difference in this request is the external adjustment for large loads. And that is -- that is based on customer information. It's a very reasonable expectation of the load that we have to serve.

It uses mathematical techniques to better inform this Commission. And we're very confident that the numbers that we have produced to support this request are the appropriate numbers that -- that represent the current customers' needs.

Q But this methodology has caused us to be severely behind, even in the Plant Vogtle construction, increase the value of this project, and now has put these rates -- these increasing rates on ratepayers.

So what gives us the confidence that this methodology is going to be something that will not cause these problems again in the future?

A (Witness Grubb) So a few things there. First off, it's not a problem. These -- these loads are an opportunity to continue to put -- you know, benefit all customers.

And the load forecasts in Vogtle, I don't know what that direct correlation is there. I mean, Vogtle was a very -- is going to be a very successful resource

for this state. It's had its challenges, but we've talked about it was re- -- you know, starting the nuclear industry.

But that has nothing to do with the forecast methodology that we're talking about here. So I don't know what that correlation is. So, again, we have an opportunity for the state and for our customers to benefit everybody with these load forecasts.

Anything to add, Mr. Valle?

A (Witness Valle) No. Nothing.

Q I mean, the correlation here is that your inability to be able to forecast and provide risk analysis for a project that now increased. It's now, what, $30 billion for Plant Vogtle, seven years behind schedule. And, yet, all of those increases were put on ratepayers.

That's what I'm asking is that --

COMMISSONER McDONALD: Mr. Hewitson?

BY MS. SCOTT:

Q Should we have confidence in this methodology when it was not beneficial to ratepayers for Plant Vogtle?

That's -- that was the line of questioning.

MR. HEWITSON: Yeah. Chairman Shaw, I would object to the question as irrelevant. But the

Vogtle proceeding is already wrapped up and -- and that decision has nothing to do with the 2023 IRP Update.

And as Mr. Grubb has just explained, the forecasting methodology that they are providing to this Commission and defending in their testimony has nothing to do with the Vogtle construction.

CHAIRMAN SHAW: Ms. Scott, if you would, just try to keep your questions based on the testimony in this docket.

MS. SCOTT: Yes, sir.

We're just talking about forecasting and the ability to be able to do risk analysis. That's all. Regardless if it's Plant Vogtle or the fuel loads, we want to make sure that the methodology is conducive and not putting undue rate increases on ratepayers.

MR. VALLE: So I -- I would say, Commissioners, that -- that, you know, to the risk analysis mention of this, this is exactly what the new adjustment for large loads does. You know, this probabilistic method gives you information about the likelihood of certain events and it's the traditional based tool that is used in risk analysis.

So that -- that part is covered. And -- and it

does it well to identify the load that we have to serve and to ensure that we keep our system reliable and -- and affordable for our customers.

BY MS. SCOTT:

Q Okay. You mentioned PPAs particularly with Mississippi Power. What are your plans, if any, to offset these PPAs with the IRA?

A (Witness Grubb) With what? I'm sorry.

Q The IRA. Did you get IRA money?

And, if so, what are your plans to offset the PPAs with the IR money -- IRA money that you received?

A (Witness Grubb) So Mr. Bush can add in here, if needed. But the IRA, we're looking at it for the -- the BESS resources, but not the Mississippi PPA.

The Mississippi PPA is not even unit specific. It is just capacity from Mississippi's system. So there is no IRA treatment on a -- on a system sale for a PPA.

We're looking at it -- and we'll leverage it for battery energy storage systems, but it's not applicable to the Mississippi PPA or even the Santa Rosa.

COMMISSIONER PRIDEMORE: Have you received IRA or IAJ money for anything that's filed in this docket?

MR. GRUBB: Have we received it yet?

MR. BUSH: No.

Commissioner, no --

COMMISSIONER PRIDEMORE: Did you apply -- did you apply for it?

MR. BUSH: Because we haven't initiated the projects really yet, we haven't applied for that.

COMMISSIONER PRIDEMORE: You haven't applied?

MR. BUSH: But we have included the -- the benefit of the IRA in our economic analysis for all the projects for which it applies.

And we will be applying for II -- IIJA --

COMMISSIONER PRIDEMORE: IIJA.

MR. BUSH: -- funding, as applicable, for those same projects.

COMMISSIONER PRIDEMORE: Can you walk through within this filing and this docket what it is that you plan to file for IIJA money for and IRA money?

MR. BUSH: Yes.

COMMISSIONER PRIDEMORE: Okay.

MR. BUSH: Would you like me to do that now?

COMMISSIONER PRIDEMORE: If you have it, certainly.

MR. BUSH: Sure. From an IRA perspective, the IRA is laid out to where there is a number of different funding opportunities. Most people talk in terms of the 30 percent funding, but there is the

requirement for -- to meet the prevailing wage and apprenticeship to get the 30 percent funding. Otherwise, it's only about 6 percent benefit.

But -- so our plan is to make sure we hold all of our EPC contractors to ensure that we get the 30 percent benefit through the IRA. Other benefits the IRA has are for energy communities, which none of the current facilities that we're deploying are actually in those communities at this time.

And domestic content. And domestic content could be a possibility for some of the projects. We haven't made final decisions.

Again, when we make a decision, we look for the best value for our customers. And so what we've seen in the marketplace is domestic suppliers raise their price because of the added benefit that others get. And we've seen it on the service side as much as a 20 percent increase in price.

So what -- what we do is we look, again, for the best value and we'll apply that as the opportunity. Evaluate that for each opportunity to make sure we pursue that.

MR. GRUBB: It's a -- oh, I'm sorry.

COMMISSIONER PRIDEMORE: Have you done the economic analysis to determine what the economic

impact to the company would be if you apply for the IRA or IIJ funds related to this docket?

And, if so, what's the dollar amount?

MR. BUSH: Oh, the specific -- I'm sorry, Commissioner. I --

COMMISSIONER PRIDEMORE: Yeah.

MR. BUSH: I don't have the specific dollar amount.

COMMISSIONER PRIDEMORE: Yeah. Okay.

All right. Go ahead.

MR. GRUBB: Commissioner, we -- real quick. You did ask what would we apply on. Just to be clear, for in this filing it would be on any of the battery --

COMMISSIONER PRIDEMORE: The BESS.

MR. GRUBB: -- energy systems, but not the others.

MS. SCOTT: Okay. Thank you, Commissioner Pridemore.

And I would ask the Commission if there was any way that we could get that data that Commissioner Pridemore just mentioned.

BY MS. SCOTT:

Q In looking at the data from the Federal Energy Regulatory Commission, again, I want to go back to this.

You failed to create accurate forecasts for future demand for at least 15 years. The forecasts from 2007 to 2020 that were used to justify new generation, including Plant Vogtle, never materialized.

So has the Commission ever held you accountable for submitting flawed low-growth estimates year after year?

A (Witness Grubb) And so, again, I would disagree with flawed and incorrect forecasts. In every IRP -- and Mr. Valle can add on here as needed -- we do report back the -- the range of accuracy of our load forecast that was in the prior IRP. And it's all within 1, 1 1/2 percent, something like that.

So he could speak to that, but we don't have flawed forecasts. This, again, is a change in the landscape in the state and the nation and the economy. So I'll let Mr. Valle speak a little bit more to that, but I would disagree with "flawed forecast."

A (Witness Valle) Yeah. So I would add that our forecast is very accurate. When you compare the performance of the forecast year after year, the average error -- average deviation that we have had for the last ten years is less than 1 percent. It's .5 percent. So it's very much on -- on target.

Now, we do acknowledge the fact that when you

do the forecast, you take a snapshot in time, you -- you identify certain assumptions, right, and it's natural to expect that with the dynamic nature of our economy and our -- our environment, those assumptions will deviate from -- the actual will deviate from the assumptions. And so natural deviations would happen.

That is -- that is not an anomaly. That -- that's something to be expected. And that is the reason why we develop a new forecast every year.

Q Okay. Last question. Georgia's grid is vastly overbuilt with reserves of 40 percent, or nearly three times the annual amount recommended by the National Electric Reliability Corporation for the southeast, which is 15 percent. Those reserves were calculated before Plant Vogtle's capacity got added to the grid.

Does it make sense to add more capacity -- we're talking about 6,000 megawatts versus the 2,100, when the grid was -- when the grid was already overbuilt?

And, again, you-all talked about the fact yesterday that you had capacity.

MR. HEWITSON: Mr. Chairman, I would ask if Ms. Scott could provide some sort of data to the witnesses to support the premise of that question. Because I don't think that there's anything before the Commission or anything in the testimony that

supports it. And, quite frankly, that's contrary to what the -- what all of the witnesses have been testifying to over the last day.

CHAIRMAN SHAW: I mean, Ms. Scott referenced where -- if you would remind us where that information --

MS. SCOTT: The NERC, the National Electric Reliability Corporation.

MR. HEWITSON: That was the 15 percent. She said that the system was overbuilt by 40 percent. I would like to know what the basis of that statement is.

MS. SCOTT: We can provide the data. I can provide it.

CHAIRMAN SHAW: Thank you, Ms. Scott.

MS. SCOTT: Okay. Thank you. Thank you.

CHAIRMAN SHAW: Is that it?

MS. SCOTT: Yes.

CHAIRMAN SHAW: Okay. Thank you.

All right. That concludes the first page on the sheet.

So next is MARTA.

MS. STURM: No questions at this time.

CHAIRMAN SHAW: No cross.

Microsoft Corporation.

(No response.)

CHAIRMAN SHAW: Resource Supply Management.

MR. BAKER: Good morning, Commissioners. Good morning, panel.

MR. GRUBB: Good morning.

MR. VALLE: Good morning.

MR. BUSH: Good morning.

MR. EVANS: Good morning.

MR. BAKER: Robert Baker representing Resource Supply Management.

CROSS-EXAMINATION

BY MR. BAKER:

Q Let me just start off with some clarification -- a couple of clarification questions from yesterday's testimony.

I know we've gone over the -- the amount of battery storage, but is the company's request for additional battery storage to ask for 500 megawatts of additional battery storage, in addition to the existing approved 500 megawatts, or does the company want a thousand megawatts more than the existing 500 approved?

A (Witness Grubb) Yeah. So it's -- it's a thousand. So the 500 megawatts is the RFP that was approved in the '22 IRP. And this is an additional thousand megawatts to help meet the earlier capacity

needs.

Q So it's a total of 1,500 megawatts of battery energy storage that the company is asking for at this time; is that correct?

A (Witness Grubb) Correct. And -- and also the All-Source RFP will allow storage bids, as well.

Q Okay. And let me ask Mr. Evans a question regarding the installation of the battery energy storage at the Air Force bases.

Will the military bases have access to the battery energy storage once they are built in case of, say, a national emergency to keep those bases operational?

A (Witness Bush) We -- from a physical capability, these batteries are not located -- will not be located on the base themselves. So not -- they're not physically connected to the -- to the bases.

Again, I -- if some mechanism were put together through a transmission system to allow that to happen, that can -- that could occur. But our current design is not for us to do that. Our current design is to have the batteries at those sites and fully controlled and operated by the operating companies.

Q All right. Do the existing solar generation facilities at those bases -- are they accessible to the

military bases for the generation to be used on the military bases?

A (Witness Bush) I don't -- I can't remember the specifics for the Robins and the Moody facilities. As I recall, we've allowed that should the base invest in that as an opportunity -- I may not be recalling it specific -- directly for these two specifics bases. But if those -- the bases were to invest appropriately, then they -- that we could arrange the system to allow that. But it's my understanding that that has not occurred.

COMMISSONER McDONALD: So I -- in those first three solar projects at Benning, Gordon and Stewart, in the contract -- and I stand to be corrected.

But in the contract -- the initial contract, if there's a national emergency, that power can go right to the base. Otherwise, it goes on the grid and then the company sells back to the base for the power that they use.

MR. BUSH: That's right. I think that's right, Commissioner. And those are actually located on the bases proper.

MR. GRUBB: On the base.

MR. BUSH: And the ones that we're talking about here are actually not on those bases.

CHAIRMAN SHAW: Well, they're right -- they're

just next-door adjacent.

MR. BUSH: One is -- one is fairly close. I think the other is a mile or so away.

CHAIRMAN SHAW: I've been to both of them. I mean, you can see the base from each one of those. And I was told then when I asked that same question that there was a -- an MOU where the -- in the event of a catastrophe, that the base would be able to procure that power.

COMMISSONER McDONALD: Those projects at those three that I was talking about are on base property.

MR. BUSH: Yes, sir.

COMMISSONER McDONALD: On Robins, it's a different setup in regards to the property that -- that that array is going to be -- is on.

MR. BUSH: Yes, sir. That's correct.

COMMISSIONER PRIDEMORE: So why would these proposed BESS projects not be available to the military in -- in national crisis?

Why would they be treated differently than the solar that's --

MR. BUSH: I don't know that we would need -- we would need to treat them differently. It's just that that hasn't been -- we haven't had discussions with the base at all in that direction whatsoever.

So we just -- we haven't considered it at this point in time.

MR. BAKER: Thank you. Thank you.

BY MR. BAKER:

Q As I was reviewing your prefiled testimony and the company's updated IRP report, it was interesting to note that the focus of the -- your testimony and the report seems to be on the increased demand for winter capacity, rather than summer; is that accurate?

A (Witness Grubb) That is correct. It's actually capacity and demand for the whole entire annual period, but the reliability the first year in which we need to add generation is in the winter. So, obviously, we'll serve them year-round, but winter is the one that drives the need for the addition of capacity.

Q Okay. So the winter demand is driving this need for this filing?

A (Witness Grubb) So winter reliability is driving the need. So as we've talked about in the last two IRPs, Commissioner, we've -- with y'all's approval have moved to seasonal planning. Because as things changed on the system, resource types, loads, winter also became a reliability season we needed to focus on and it actually is driving it.

So we still are a summer-peaking utility, but

the reliability risks, such as today, are in the winter more than they are in the summer now.

Q Could you explain why the winter reliability risk is increasing?

A (Witness Grubb) Yeah. So we've -- we've had five factors in the last two IRPs. Part of it is there has been a narrowing of weather normal summer and winter loads.

You've got more -- because of cold weather, gas units have some more challenges. We have winterized them and -- and made those units before a lot better. They performed well today.

You also -- I'm trying to think of the others. Renewables. Renewables help a lot more on the capacity needs in the summer because summer peaks in the afternoon when it's hot and sunny. The winter, it peaked this morning before the sun was up.

And so I think the other one was -- I can't remember the other two. But it's the same five reasons we've listed in the last two IRPs about moving there. So it's not just loads. It's loads and then also resources.

Q Resources.

Oh, but does the winter heating load have a major impact on the winter reliability issue?

A (Witness Grubb) Well, so that is why those

peaks have narrowed over the last seven, eight, nine years. If you think about everybody has got an air conditioner; right?

And air conditioners continue to get more efficient. So that load, all else equal, doesn't grow as much, where the winter has. There has been a growth in electric heating.

But, again, it's not just the loads. That's a big part of it, but it's also the resources. Again, so our resources that -- like solar, we've added thousands of megawatts.

It helps a lot more in the summer than it does in the winter from a planning standpoint. And then the gas units, and any units, in the cold weather have more challenges than they do in the heat.

Q So would you say that the need for the 1,400 megawatts of the combined cycle -- not combined cycle -- combustion turbine facilities at Plant Yates is driven or necessitated by the winter heating demand, say the initial daytime winter heating demand?

A No. I mean, it is -- it is load in the winter, plus the reliability risk. So we plan to the 26 percent reserve margin in the winter and the 16 and a quarter in the summer. And so when we look at weather normal winter loads versus our resources, that is the earlier need.

The summer need's about two years behind it. So the Yate- -- all the resources here are driven from a timing standpoint by that winter need, but they obviously are available in the summer, as well.

So the Yates CTs can help with any peak. The timing is based on that winter need to add generation. And it's two years before the summer need.

Q Okay. Based on the company's resource mix study, Vogtle Unit 4 is not operational during 2024. If Vogtle Unit 4 is not operational now, what effect would that have on the 2023 updated IRP load forecast?

A (Witness Grubb) If it -- if Vogtle 4 does not come online by when?

Q This year?

A (Witness Grubb) Well, I mean, we still would have enough capacity, but we -- we fully expect Vogtle 4 to be on schedule.

Q I -- we --

A (Witness Grubb) So, I mean --

Q I've heard that line before, but --

A (Witness Grubb) Yeah. But if it delayed, we'd still have enough capacity in the next year or so to meet our target reserve margins.

Q Okay. So is -- does -- in your resource mix study, it shows that Vogtle 4 is not operational during

2024. What impact did that have on -- on the application you're making now?

Did that increase the need for the 1,400 megawatts of combustion turbine generation?

A (Witness Grubb) No, it did not. So Vogtle 4 is in the models. It's just not in the winter of '24 because it's not online right now.

And so the resource mix study is solving for system needs, which doesn't happen for a few more years. So Vogtle 4 is in the math to look at what has to be added. So these resources in this update are in addition to Vogtle 4 coming online.

Q Okay. At page 7, line 20, you indicate that the company needs to own and operate battery storage systems.

Won't the battery storage systems be located in Georgia?

A (Witness Evans) Are you referring to our testimony?

Q Yes, sir. Yes. Page 7, line 20.

A (Witness Grubb) Yeah. So Item 4 where it's talking about the thousand megawatts of BESS?

Q Yes, sir.

A (Witness Grubb) Yes. Those sites that we've looked at, the -- obviously, the three that we've

identified, Robins and Moody and the other, which we have not announced the name, but it is in Georgia. And then we are focusing on Georgia for the other megawatts for batteries.

Q Okay. Shouldn't the battery storage projects be put out to a fixed price competitive bid for all bidders so that ratepayers can get the benefit of the lowest responsible bid for the construction of these new units?

A (Witness Grubb) So we talked a lot about RFP yesterday and it could get a little confusing. So I think, Mr. Baker, you're asking about not a competitive RFP per the Commission rules, but as Mr. Bush develops these company batteries, is he putting it out for developer or --

Q Well, is the company trying to get the best price for the construction of these units for the benefit of everybody who's a ratepayer?

A (Witness Grubb) Absolutely. I'll let Mr. Bush hit really quickly what he did yesterday on how they -- they do that.

A (Witness Bush) That's right. As we talked about yesterday, we do go out to the market to provide the -- to get the lowest cost, best option for our customers. And we do request fixed pricing to do that.

So, again, to limit the risk to our customers and provide the best value, that is the structure of the agreements that we put in place to ensure we can do that.

Q Also at page 7, line 23, the company is asking for any development costs not useful or transferable to other projects be deferred to a regulatory asset for recovery in the next base rate case in the event the request is denied.

Is there any limit on the amount the company seeks to be deferred and recovered?

A (Witness Grubb) So, again, those are the development costs. And so we -- there's not a limit, in terms of we're going -- we're moving forward with the need to develop those resources so they can come on time -- come online in time to serve the need. If the Commission denied that request, then we're asking for recovery. So there's not a limit, other than we are moving towards contracting and certification as soon as we can.

Q Okay. Looking back at the past PSC precedent, in the -- regarding the Stewart County nuclear development request the company made to the Commission, the Commission set a limit on the company's recovery. The company had asked to recover 175 million in cost -- development costs, but the Commission limited the

recovery to $99 million.

Is that something that the Commission could do today to try to put a reasonable cap on development costs that are not useful or transferable to other projects?

A (Witness Grubb) So the Commission can do as they need to, but -- on my prior question, let me reiterate, of course the Commission has ultimate authority on what costs we recover on that development.

Stewart County is a different issue. That was a lot of site work for future nuclear sites. It wasn't a specific resource development. So this is different in that these development costs are for the actual physical resource.

So, yes, the Commission could. But, again, we've got to -- we've got to be able to continue to move forward with those to develop the resources to have them come online in time. But, yes, at the end of the day, the cost recovery is the Commission's authority.

Q Okay. I mean, it would only occur in case of the fact that the application was denied --

A (Witness Grubb) That's correct.

Q -- and the -- and the costs are not transferable or useful somewhere else. That's -- that's the caveat there.

A (Witness Grubb) That's correct.

Q Okay. And I'm not asking for any specific number. Referring to the 1,400 megawatts of combined -- combustion turbine generation that's being proposed, is it -- would you say the cost is going to be above or below $1.4 billion for that project?

I'm not asking for specifics. Just want to know generally: Is it going to be above or below $1.4 billion?

A (Witness Grubb) And when -- and when you say costs, which specific costs are you asking about?

Q The development, the construction cost for the construction of the 1,400 megawatts of new combustion turbine generation sited at Plant Yates, including whatever ancillary costs that have to go in. You had mentioned transmission upgrades that have to be made to a -- to be able to fully utilize the 1,400 megawatts once it's developed.

Would you say that the overall cost is going to be above or below $1.4 billion?

A (Witness Grubb) So that value is trade secret. So I don't want to indicate what its relationship to your $1.4 billion is enough. I will say that the parties in this case that have discovery rights have that information and so does the Commission.

Q I -- I don't want trade secret information.

I'm not asking you to put a dollar -- a specific dollar amount. I'm just asking for a ballpark.

Is it above or below $1.4 billion? That's not trade secret. That's just a general reference.

MR. HEWITSON: Well, it's not a general reference. It's a general reference in relation to a specific amount. So it's trade secret information.

If Mr. Baker wants that information, he can execute a confidentiality agreement and we would gladly provide it for him. Everyone else who has executed that agreement has been provided that information.

BY MR. BAKER:

Q Let me turn now to -- to page 8, line 6 of your prefiled testimony and ask you: Will existing customers be allowed to participate in the new tariff-based demand response program?

A (Witness Evans) Yes.

Q Okay. So long as they meet the criteria for the program?

A (Witness Evans) That's correct.

Q Just like new. Okay. So long as everybody meets the criteria.

Mr. Grubb, I hate to do this to you again,

but --

A (Witness Grubb) And we've been here for you --

Q You have done a great job and I -- you know, you've -- and you've -- and I've listened to you carefully and whatever you said. You do an excellent job.

I understand you say that based on the company's estimates right now that there will be downward pressure put on rates from the construction -- from the costs associated with all these new projects, for the battery storage, for the combined combustion turbines, and for the PPAs.

Isn't that -- and I -- I hear you. You know, you need to -- and Mr. Valle has made a point that, you know, you've got a certain number of megawatts of expected projects that you are expecting will come online.

Isn't there a certain amount you have to have in an -- you know, an "X" number that you have to meet in order for your prediction to come true that there will be downward pressure?

And let me just give you a hypothetical. If your -- if your expectation is you're going to have 100 megawatts of new projects coming online that will offset all these costs, but in reality only 50 megawatts

come online, is that going to put downward pressure on rates?

A (Witness Grubb) All right. So we -- we talked yesterday, we are highly confident in our -- in our statements because we have confidence in the costs and we do -- as we mentioned yesterday, the revenues that we've included in that analysis are at a lower load forecast than the load forecast we're using for -- in this filing.

We've -- we've thrown some -- I wouldn't say conservative, but there's -- there's -- we've looked at if -- if half of the loads show up, you're still able to make that statement. And so that's part of it.

The other thing is if the loads don't materialize, there are some things we can adjust on the plan. So, for example, we've identified we need to get another 500 megawatts of batteries. If we don't need those 500 megawatts of batteries, then we don't procure those 500 megawatts of batteries.

So we're highly confident in that because we have that 50 percent of that load forecast is in -- or the -- the PF50, as we called it yesterday, a little bit lower load forecast, those revenues overcome the revenue requirements of the projects.

And, again, at the end of the day, we feel highly confident that that load is going to be there.

A (Witness Valle) And I would add, Commissioners, that because of what we are seeing today, in terms of the economic activity, the economic development activity, the pipeline -- the size of the pipeline from the time that we developed this forecast that we have in front of you versus what we have today has grown 25 percent.

So although the last -- the load can change, you know, economic conditions can change and it can affect the -- the forecast, it's unlikely because we're already seeing more in the pipeline from what we have included in this -- in this filing.

A (Witness Grubb) Yeah. And -- and to that pipeline, Mr. Valle's point, the loads that we are asking for in the case are below half of that pipeline. So we're not asking for all of it. So your -- there's a lot of potential for continued growth.

Q But it's still, basically, in the end, there's no guarantee. You're -- Mr. Valle is doing his best to do -- make the predictions on the P50 and P95 load forecast; correct?

But he's -- he can't guarantee with a hundred percent accuracy. Nobody can.

A (Witness Grubb) That -- that's correct. However, everything we do -- when you're talking 10, 15 years down the road -- are projections. And as we've

said, we have a really good track record on the forecast. We have a high confidence in the cost.

So, yeah, but we are -- yeah, you can't ever guarantee anything. But this is -- when you look at the amount of customers that want to come do business in the state of Georgia, the confidence level on -- on that statement that the loads and the revenues will -- will be greater than the cost of this resource plan is a high level of confidence.

Q But no guarantee?

A (Witness Grubb) I mean, if that -- there is no guarantee of anything, but highly very -- very high confidence.

Q Mr. Valle, you have -- you explained in detail how right now you've got -- I believe you said yesterday you've got 17,000 megawatts in requests for new capacity; is that accurate?

A (Witness Valle) That's -- that is the size of the pipeline. That is the size of the announcements in the pipeline.

Q And that -- and that is growing, as I just heard Mr. Grubb say?

A (Witness Valle) Yes. Yes, it is growing.

Q So would you say that this -- I mean, this has never occurred in the history of Georgia Power that this

-- this magnitude of potential growth has ever materialized in the history of the company. This is unheard of.

A (Witness Grubb) So, again, we mentioned yesterday, it's not just Georgia. It's a -- it's a national issue. There's several other states that are seeing the same thing.

And it's an opportunity. It's an opportunity to add customers and have a larger customer base over which to cover -- spread costs and lower rates for everybody.

Q I understand it's beyond Georgia. But this is the first time in Georgia history that this size, this magnitude, this increase has ever been realized; is that accurate?

A (Witness Grubb) That is true.

A (Witness Valle) Yes.

Q Okay. Now, Mr. Valle, when you do your -- your P -- your analysis and you make your determination, do you look at factors regarding these applications for new load to determine just how serious these applications are?

I mean, hypothetically I could come to you and say: Oh, I'm -- I represent RSM Data and we need 200 megawatts of -- of new generation in Conyers.

And -- but wouldn't you need to know more to know if my request for 200 megawatts was a serious potential request that would actually materialize in two to three years down the road?

A (Witness Valle) Absolutely, Mr. Baker. And that is a great question, Commissioners, because it is something that, in order to produce an accurate forecast, you have to entertain; right?

And that is why in order for the company to include as a customer within the portfolio of large loads, it has to meet three conditions. First, you need to have -- identify sites.

So it's not just the intention of coming to the state. It's also the -- they had to do the homework to say: Okay. We're going to be locating in this part of the state, and have some certainty about the specific site.

Second, they need to have engaged actively with our company regarding the electric service. And that -- that process, sir, is to weed out -- what is being asked in this question is to -- is for us to assess how realistic, how possible this load is; right?

And then they have to provide us with -- with a ramp-up assumption, how much of the load is going to materialize over time.

Only when those three conditions are met we include that -- that, you know, potential customer in the forecast with the appropriate likelihood to be -- to be served.

A (Witness Grubb) And so, Commissioners, this is -- it's not -- this isn't like an economic data series projection. These are tangible projects that we are in discussions with the customers.

They are looking at siting. They're looking at land. I mean, they're people that are seriously considering coming to Georgia.

That's all the type of data that's in the information Mr. Valle is talking about. It is tangible information and tangible projects.

Q Well, Mr. Valle, I mean, if -- if for RSM data, would you ask me if I own -- or if the company owns property, actually has physical ownership of property to locate my potential data center on?

Would that be something that you would be inquiring in to see just how serious an application is and go into a lot of detail, such as: Do you have the financing for this project? Do you have the experience for this project? Are you just some guy standing at a podium coming up with a new company idea that has no background whatsoever?

Would you go into those kind of details --

A (Witness Valle) Absolutely.

Q -- to determine the ver- -- the seriousness?

A (Witness Valle) Absolutely. We have to. We have to. Because in this hypothetical example, you know, one of the questions that we have to ask and get a yes or no answer is the question of: Is this customer -- has this customer selected the state of Georgia to do business; right?

And in order to answer yes or no to that question, there has to be some tangible commitments. If there hasn't been some tangible commitments, then the answer is, no, they are still deciding between Georgia and other states.

So we have to make sure that they -- that we see commitments from the customers to make that determination. So, yes, we -- we get into -- and it's part of the intelligence that our -- our company gathers; right?

It's the -- it's why this should give this Commission confidence of what we have. Because there is nothing better than customer information; right?

This is, again, not something coming from a -- from a third-party consultant or from the news. This is, like, actual negotiations, actual intelligence that we

gather. So we feel very comfortable, very confident about -- about the forecast.

CHAIRMAN SHAW: Would you -- would you say that when -- when you're collecting that -- that data and that kind of information on these potential customers, in your experience in dealing with these -- I'm just going to reference -- talk about the data centers.

Would you say that it's possible that some of these prospects are looking at Georgia mainly because of the energy capacity availability in comparison to other sites or other states?

MR. VALLE: I think -- I think it's a combination of factors, Commissioner. It's -- it's -- yes, it's -- the availability of capacity is one of the factors.

It's also pricing, right, because we have competitive pricing. We also have the infrastructure because we have to remember that, you know, you can't just locate a data center anywhere in the -- in the country. You have to have the infrastructure to -- to be able to provide the service for them. So Georgia meets -- checks the boxes in many levels for -- for these customers.

We also have a very good school system. We

have professionals. So it's -- it's the -- it's a confluence of factors that have made Georgia successful that makes this customer wanting to come to our state, yes.

MR. GRUBB: So, Commissioner, I think they see it's challenged in several other states; right?

So I think we've talked about why people like doing business in the state of Georgia, which is a lot of the reasons Mr. Valle just hit. But I think also with the approval of this plan going forward, we can have even better conversations with those customers; right?

Because they'll know that we have a plan in place to help meet these needs.

CHAIRMAN SHAW: The main reason I ask the question is because I personally heard the CEO of a neighboring state's utility -- electric utility publicly say that they don't want data centers because they can't support them because they don't have the capacity.

MR. GRUBB: Right, right. And, again, so we -- we want to be able to offer the opportunity for any customer that wants to do business in the state of Georgia to do it. And so that's why we're looking at this -- this load forecast as an appropriate

level to capture those.

And data centers are -- when that load gets added to the system and the way we price it, it helps all customers' rates be lower because of those -- those good -- those good industrial or commercial customers that come to the state.

COMMISSIONER PRIDEMORE: Have we put forward a tariff on these data centers or a standardized pricing yet?

MR. EVANS: We haven't done that, Commissioner. We think the current tariffs and rates that we have give us the tools we need to -- to ensure that they put downward pressure on rates and balance that with attracting beneficial load to the state.

We have -- as our costs increased overall, not specific to data centers, but we did evaluate what those costs were and -- and factor that into the offers we were making to competitive load there going forward.

COMMISSIONER PRIDEMORE: But the existing CNI tariffs don't account for a con- -- a length of service contract. Are we putting a length of service contract on these data centers?

MR. EVANS: No. We -- we do have contracts that contract them for a load ramp and the

availability of the capacity, things like that. We don't --

COMMISSIONER PRIDEMORE: But a length of time. Like they're -- they're going to stay in business and use Georgia Power as their electric provider for three, four, five, ten years?

MR. EVANS: I don't believe we've done that. We have mitigated risk in requiring up-front payments for local and direct investment that serves just those customers, accelerating those payments and not having it factored into their ongoing rate, things like that.

COMMISSIONER PRIDEMORE: Within your modeling -- I know we've talked specifically about data centers and about new manufacturing growth. But within your modeling, are electric vehicles modeled as part of this -- this need for capacity?

MR. VALLE: Yes, they -- they are. They're not part of the external adjustment of large loads, but it's part of the external adjustment for electric vehicles that we've been continued -- we have done that in the past.

COMMISSIONER PRIDEMORE: Has that adoption rate been lowered as we've watched EV sales decline over the last eight to nine months dramatically?

MR. VALLE: Uh-huh, yeah. Actually, they have -- they have increased. I wouldn't say it has been an explosion, but they've been gradually -- the adoption of electric vehicles have been -- have been, you know, increasing over time.

The recent developments of -- of production announcements being slowed down is probably going to be something that we are going to capture in the next business cycle. But -- but so far EV has continued to be strong.

In this budget iteration, we included heavy-duty applications. They're not going to materialize until, like, later in the '30s, probably into the '40s. But, you know, in our practical view, we are -- we are looking ahead and we're trying to -- to identify the -- the consumptions for -- of EVs, yes.

COMMISSIONER PRIDEMORE: But we've seen -- I mean, I'm -- I'm looking right now at the New York Times. Now, they don't always tell the truth, as we all know, but I think in this -- there's some data here that -- that EV sales have -- have sharply declined.

MR. VALLE: Yeah.

COMMISSIONER PRIDEMORE: They are far from the

projections that have been put out over the beginning of 2024 and then going back the last two quarters of 2023.

Has Georgia Power adjusted their EV model within the methodology that you're using to be able to do these projections based upon that trend?

MR. VALLE: Absolutely. Good -- good question, Commissioner. It's a -- as of now, we haven't. But, you know, we -- we rely on the expertise from EPRI to -- to give us that -- those projections.

Right now the -- the EV adoption represents about 6 percent of the total new vehicle registration in the state of Georgia. So it's not -- it's not a very aggressive number.

But, absolutely, as those -- you know, the -- the trends that you're mentioning materialize, we would capture it in the -- in the next iteration for sure. It's not a --

COMMISSIONER PRIDEMORE: But you didn't capture -- they're not captured?

MR. VALLE: Not -- not captured on this one. So just to give you an idea of the --

COMMISSIONER PRIDEMORE: Decline --

MR. VALLE: Of the size of what we're looking at, as the -- the electric -- the peak demand for

electric vehicles in 2023 was about 20 megawatts. So in comparison with the thousands of megawatts that we're seeing from -- from the large loads, it's a -- it's a tiny amount.

But, that said, it is top priority. Even if it's small, it's a top priority and it's something that we've been tracking, so...

COMMISSIONER PRIDEMORE: Are you using EPRI's analysis on AI adoption as the -- the formulaic data center increase that's being put into your model?

MR. VALLE: No, not -- not at this point. So what we are -- what we are doing with -- not just the -- not just data centers and AI, but -- but with the portfolio of large loads, we've been tracking the development of this portfolio. And one question that is yet to be determined is: Is this going to be the -- the beginning of a new era where we're going to see increases in load continuing at a 4 or 5 percent, you know, for the foreseeable future, or is it just a wave of projects that are coming to the state and then they're going to normalize to a lower level?

That's to be determined. We've been looking at research and -- and trying to inform ourselves for potential trends developing. But at this point, we

haven't.

COMMISSIONER PRIDEMORE: Thank you, Mr. Baker.

VICE-CHAIRMAN ECHOLS: Can I follow up on this question? I mean, my -- my greatest concern is that your estimates are wrong or some of these people don't come. We secure all this power and your revenue falls short and we have to go to ratepayers and claim that.

We -- we just can't -- we just can't do that.

MR. VALLE: Absolutely.

VICE-CHAIRMAN ECHOLS: And I'm -- and I'm -- I'm wanting some reassurance from you that -- you know, that -- that we're protected against that.

Can you give me -- can you give me a strong assurance on that?

MR. GRUBB: Yes.

MR. VALLE: Let me give you -- let me do that from a forecasting perspective. Mr. Grubb can -- can -- can complement it from a -- from a resource perspective.

So if you look at the total size of the pipeline of projects, right, the 17,000 megawatts that was mentioned yesterday, what we are telling this Commission is that less than half of that -- so about 46 percent, 7,000 megawatts, give and take --

are going to come, based on our estimation, with a 95 percent confidence; okay?

So -- so that's the load that we're -- that we're aiming to have. That represents less than half of the pipeline; okay?

If you look at that -- if you look at the adjustment that we have included in the forecast, half of that is already won. So half of that amount is -- is already made out of projects that we have secured and Georgia Power is going to have to serve. And the other -- the other half is -- is potential.

So I think the load is real. I think the assurance comes from the fact that there is a momentum; right?

There is an enormous amount of load that is coming. This -- this has been -- I hate to use the word "unprecedented," but it is. And -- when we first include an external adjustment in budget 2023, that amount, by the time that we went into -- into March, it doubled. And then from March into June, it doubled again. And so -- and now, we haven't done a new forecast, but the -- the economic activity in the pipeline has grown 25 percent.

So it's a tremendous momentum that we have. If -- if any concerns, I would say maybe there is

upside -- upside risk, upside potential for the load. The load that we may have in front of you may be -- may be on the low side.

It's to be determined. We would like to do -- to do something more scientific to -- to give you that. But -- but I think that should give you assurance for -- for what we have.

It's a -- I know that the numbers that we have included in this request are big. And, again, they are unprecedented; right?

We haven't seen this activity of load. If you look at the wins that we have in 2022 and 2023, those represent 40 years of growth in just two years. That is -- that is just something that can -- can put a lot of perspective of how fast and large this activity has been.

But because it continues to grow, because it is -- you know, we are giving you an estimate that is less than half of what the pipeline is out there, and because the pipeline is continuing to grow, it should provide this Commission assurance.

And -- and you're not alone in this one. It's -- it's keeping me awake at night thinking about the possibility.

MR. GRUBB: Yeah. I think, Commissioner, one

other -- a few other points. Mr. Valle threw out kind of a load forecast number. Around -- around half of that we've already gotten awarded to be their electric provider. So it's a combination of what we've already won, plus projections.

And then on the resource -- I'm sorry.

COMMISSIONER JOHNSON: That -- that 30 -- half of the 7, the 35?

MR. GRUBB: Somewhere -- yeah.

COMMISSIONER JOHNSON: That's booked?

MR. GRUBB: Somewhere in the -- yeah. We've won 4,000 megawatts. So you've got to factor in how that ramps and grows in. But those 4,000 megawatts that we've won as electric provider doesn't drive this need by itself, but it's a big part of that load forecast that's in there.

And then, Commissioner Echols, on the -- on the resource side, you know, the PPAs end at the end of 2028. If the load forecast adjustment comes in, we could sell that more than -- than we've planned right now.

If we don't get the growth, we still expect somewhere in the southeast will get it. And so we would look at selling that. That would be the first thing we'd do.

If we didn't need the additional battery energy storage systems for the thousand, we would -- we could stop that. So there are some things we can do on the cost side, too.

And then going beyond '28, your needs in the future would be a little smaller; right? So there are some things we could do on that end if the load forecast doesn't materialize.

Again, we're very confident in it, but wanted to give you that -- that aspect of it, too.

VICE-CHAIRMAN ECHOLS: Thank you.

COMMISSONER McDONALD: Could you not measure your forecasting in real-time?

Like right now as you forecast the -- the load that -- SK Battery that you serve was going to take -- when you were looking at that project, and now in the last six to eight months there's been a considerable reduction of employees in that facility --

MR. GRUBB: Yeah.

COMMISSONER McDONALD: Has the load changed from your projections or --

MR. VALLE: So that -- that is --

COMMISSONER McDONALD: That's real-time. You know, that's not hypothetical or whatever.

MR. VALLE: It is -- it is part of the -- of the range of the possibilities that we have -- that we have considered. It is a very good question because it's -- I mean, you're -- you're asking the right questions.

You're asking, like: What are the elements that could bring uncertainty to the decision that we have to make; right?

And that one in particular, we have modeled the -- what we call the load realization, the -- the percentage of the load from the announcement to what we see at the meter as a range. And we have a -- a range with certain likelihoods and -- and so it is part of it.

And -- and when you look at what their -- what the derated amount has been, it kind of fits in the -- in the range that we have. So it's -- it's very good for feedback and for -- for validating some -- our assumptions. But I would say it is part of what we -- what we consider.

MR. BAKER: Good questions.

BY MR. BAKER:

Q Getting back to the first line of questioning Commissioner Pridemore brought to you. I mean, I think she emphasized in her question the reality that there's

no guarantee in business. That while electric vehicles were the hot trend maybe a year or two ago, that trend has changed. And that's just business.

I mean, there is no guarantee that tomorrow it's going to be the same. I mean, it change -- your challenges change every day; is that accurate?

A (Witness Grubb) They do. I would say on the other end: If we don't add these resources, we know we're not going to be able to handle load growth.

Q I understand. Let me ask you a clarification. Now, you said, Mr. Grubb, that you've won 4,000 megawatts of contracts. So what does "won" mean?

Does that mean somebody just signed the contract, or does it mean more than somebody just signed a commitment to select Georgia Power as their -- as their electric service provider under the large load or territorial act?

A (Witness Grubb) It's the latter, as we showed in the filing. We showed the -- the history of customer choice wins that the company has had.

So the -- the highest we ever had in history was 300 megawatts in a year. And we had over 2,000 megawatts last year and this year.

So they have signed for requests for service. But, again, when we do this, we work with them on the

customer choice side. It's not somebody that just says: Hey, I'm bringing a data center. I want to sign it up.

I mean, it's a -- we do capture some of that in the load forecast, but it is -- it is people who have invested in projects enough that they are to the point to select an electrical provider.

Q Let me just say that you have a signed agreement with a large-load customer. Does that signed agreement guarantee that two years down the road you will actually be selling electricity to that customer?

A (Witness Grubb) Well, they are -- and Mr. Evans can help me here. They are putting investments in place and paying us for facilities and -- and looking at what it costs to interconnect to our system.

So they -- they do have -- there's no guarantee, but we have a very good track record of customers that come to the state and say -- like Georgia Power, they develop.

A (Witness Evans) That's right. And, I mean, it ensures that Georgia Power will be their electric provider; right?

Q Right.

A (Witness Evans) They say they've selected Georgia Power. And as that gets closer to operational date, more investments are done, engineering schematics,

methods of service, up-front payments, right, things like that, that mitigate that risk along the way.

Q And -- and does Georgia Power monitor that development process throughout the project's life?

A (Witness Evans) We're critical as part of that development process; right? So understanding exactly what the method of service is going to be, what investments Georgia Power has to make to connect them, things like that; right?

To ensure that where one can connect that nothing has changed about the siting of the facility, about their method of service requirements. So all along that development process, we're integral in it.

Q The comment was made during this discussion that -- I don't know if you -- I think you made it, Mr. Grubb. But you said there's 40 years of growth have occurred in two years. Isn't that a red flag just as -- from a business perspective, that this is really unusual?

This is really something we've never seen and probably will never see again?

A (Witness Grubb) Right. But it -- but it is backed up by tangible projects and people who are putting investment into place.

Q All right. Do you foresee this trend continuing or is just -- this a wave that will come and

go in a couple of years?

A (Witness Evans) Well, I think it's important to realize, as we've said yesterday, that the pipeline is only tangible projects. So there is no projection beyond the projects we are actively engaged with today. So there is no ongoing projection that it will continue beyond the projects we actually are monitoring and engaged with to -- to develop offers and provide electric service to.

Q Turning to -- and I'll just reference you, if you want to look at it -- page 20 of your prefiled testimony, line 18.

When considering the primary drivers impacting the company's updated capacity needs, was any consideration given to deferring or delaying coal plant retirements to meet the urgent needs identified in the 2023 IRP load forecast?

A (Witness Grubb) Did you -- did you reference a specific line? I'm sorry.

Q Page 20.

A (Witness Grubb) Uh-huh, yes.

Q Line 18.

A (Witness Grubb) Oh, just the -- the category of updated capacity needs?

Q Yes, sir.

A (Witness Grubb) Yeah. So, no, because the -- the coal units we have online are -- are online through the end of 2028, which is the period of time that we're -- we're addressing in this case.

Q So they're at their normal capacity factor at this time?

A (Witness Grubb) Uh-huh.

Q Okay.

A (Witness Grubb) Yes. Those plants are operating and operating today and are -- are scheduled to be here through at least 2028.

Q But if the need continues, say it's just more than a wave, that this -- this growth trend continues, wouldn't that be something to consider to meet the needs to have -- you have existing plants in place, operational, being paid for by customers, rather than going out and developing new plants that haven't been paid for?

A (Witness Grubb) Right. So we've -- the 2025 IRP is where we will address that with the Commission.

Q What is the current status of Bowen Units 1 and 2? Are they operational?

A (Witness Grubb) They're operational. There's -- nothing changed with them. In the last IRP, no decision was made. So we'll study them in '25 like we do

always, but they are operating.

Q Okay. So all the Bowen units are normal operation?

A (Witness Grubb) Yes. And the -- the ELG controls are being constructed and put in place for that plant site.

Q Could the Wansley combustion turbines Units 1 and 2 be able to be reactivated if nec- -- if needed?

A (Witness Grubb) Not in this time frame in this IRP update, no.

Q Could they be reactivated outside this time frame?

A (Witness Grubb) There -- there are some challenges and risk to it.

We did look at that, Commissioners. Some of the data requests showed that. But the timing for this update was not there.

There's permitting time frames you've got to do. You've got to figure out, you know, the gas usage and those types of things. So we'll be looking at all options going forward, but it did not -- it did not help meet the needs in this case.

Q Hands -- sorry, Mr. Grubb. Circling back again to one of our favorite topics.

A (Witness Grubb) No need to apologize,

Mr. Baker.

Q That's -- okay. Circling back to the 70 percent ownership guideline.

A (Witness Grubb) Uh-huh.

Q And that was -- that arose from a 2001 decision by this Commission and then it's -- there's a PSC rule that's a very generic reference to -- to ownership. But no -- no specific limits or guidelines were put in the rule; correct?

A (Witness Grubb) That's right. The -- the order that you mentioned, though, was when the value was set.

Q Right. Would you say that there have been a lot of significant changes in the utility industry -- and with Georgia Power and with the utility industry and with the state of Georgia since 2001, in the last 23 years, that might give the Commission a legitimate reason to at least consider whether 70 percent is an appropriate level?

A (Witness Grubb) As we talked about yesterday, the Commission has that -- that authority. The -- the 2001 was around reliability. I think the -- the driver was a lot of the things that were going on in California, which was a lot of liability risk based on market activities.

Reliability today is just as important as it

was in 2001. And I would say that when you look at the industry now with a lot of technology advancements, more intermittent resources, more dynamic aspects on the transmission system, reliability is just as important as it is today. The drivers may be a little different, but I -- there's been a lot of changes, but not all of those changes have made it less challenging from a reliability standpoint. I would say the opposite.

Q Well, would you agree that in 2001, the independent power production industry was in -- in its infancy?

I think you had referred to it was in the beginning stages of development.

A (Witness Grubb) From the -- from the gas aspects in the PPAs, I believe that's about that time, that's correct.

Q And would you say that the Commission at that time was concerned about not allowing the utility to overcommit or over- -- to put some reasonable limits to see how independent power producers developed, to see how the PPAs worked, to get some history to understand how -- how this all functions and interrelates into the operation of Georgia Power?

A (Witness Grubb) I can't speak to exactly what the Commission's thoughts were in 2001, but that could be

part of it. But, again, there's still challenges on the system today. And we've talked about PPAs have performed well.

We are -- we aren't anti-PPA at all. And we do RFPs and we've done -- you've heard me yesterday, 27 of them; right? But ownership still is different when it comes down to reliability and the ability to flexibly -- to handle the flexibility needed on a dynamic system.

Q Okay.

COMMISSIONER PRIDEMORE: Excuse me, Mr. Baker.

MR. BAKER: Yes, ma'am.

COMMISSIONER PRIDEMORE: So I understand that this panel is going to get questions about the use of the PPA. And these intervenors are going to act like that a PPA is going to provide ratepayer protection. Well, at the end of the day, what a PPA is is somebody else doing the generation and making money off of it is what it is.

The company has a -- a need to hold assets to prove financial viability long term, which -- which then produces and assists the ratepayer by overall lowering rates. You don't have to agree with me. That's just a fact. We all know it.

And I think you-all have heard from these Commissioners that the -- the biggest consideration

is coming back and allowing the company to -- to procure more resources now versus waiting for the standard IRP cycle.

I understand you're -- you're reporting that there's unprecedented growth, unprecedented demand. I don't disagree you. I hear you. All five of us are involved in economic development projects. So this is not new news to us.

It's the breadth of it and it's the extent by which the company is seeking to build out. Recognizing that this panel has said repeatedly that we don't think that there is going to be a rate increase, or no rate increase, comma, but, which was what you said to Ms. Coyle yesterday with Georgia Watch. But the one thing that's stopping a rate increase and doing -- or doing everything we can to stop a rate increase is this Commission.

What guarantees can this panel provide this Commission that if the Commission tells Georgia Power to procure the generation assets they seek in this docket that there will be zero ratepayer impact, zero rate increase on it in the company's next rate case?

MR. GRUBB: So in this filing for the loads that we expect, there will be downward pressure on

rates.

COMMISSIONER PRIDEMORE: What if your targets are off and the loads do not come in at the level by which your projections have put them at?

What then?

MR. GRUBB: We would -- we would reduce the cost on the resource side in an effort to match it as close as we could.

COMMISSIONER PRIDEMORE: But what if you've -- what if you've front built and you've put the CTs in the system, which are more expensive right now than BESS is, and you've done that work and the company is already out the funds?

What then?

MR. GRUBB: So, again, we're talking about the entire pipeline and our confidence in those loads. That's what everything is based on.

COMMISSIONER PRIDEMORE: But what if you're wrong?

MR. GRUBB: Well, if -- if we're wrong, that would not be beneficial for customers. But, also, if we don't move forward with this plan, we miss the opportunity to put downward pressure on rates.

COMMISSIONER PRIDEMORE: But what if you're wrong and you put upward pressure on rates by

building for demand that doesn't come?

MR. GRUBB: The risk to us is greater that we don't move forward and we miss the opportunity to put downward pressure on rates, based on everything we're seeing.

COMMISSIONER PRIDEMORE: That's the risk to Georgia Power, but we're here to assess the risk to the customer. And the risk to the customer is -- is that cost.

MR. GRUBB: I think the risk to the customer is the same as -- as I said -- and I wasn't talking about Georgia Power. The risk to the customers is that we don't move forward with this plan and we don't support new load growth and we don't put downward pressure on rates. These loads give us an opportunity to help all customers.

COMMISSIONER PRIDEMORE: I recognize, Mr. Grubb, that you say the phrase "downward pressure on rates." We talk about it in the regulatory world repeatedly. Define what downward pressure on rates is.

Is it a tariff for data centers that locks them into a long-term contract?

MR. GRUBB: It is -- it is adding the load that we see coming down the road to make the customer

base larger, spread all the system costs across, and help everyone's rates.

COMMISSIONER PRIDEMORE: Bigger does not equate to cheaper.

MR. GRUBB: It -- it does if your revenues coming in are greater than the cost that you're putting into that equation.

COMMISSIONER PRIDEMORE: That's a revenue that -- the revenue model takes in from that point. The amount of generation that is produced has a -- has a cost output that the company is going to have to spend to be able to serve that load.

MR. GRUBB: That's correct.

COMMISSIONER PRIDEMORE: Or that proposed load. If that proposed load does not materialize, the company is out the money from what they've put forward. What happens then?

MR. GRUBB: So all of that is at the Commission's discretion on what to allow there; right? But we are asking approval there.

But, again, we don't --

COMMISSIONER PRIDEMORE: Approval of what?

MR. GRUBB: The -- the costs that we're asking for here and certification costs going forward. So if the loads are not showing up, I mean, that's --

that's in y'all's discretion on the cost recovery side.

But, again, if we do nothing, then there is no downward pressure on rates from all these new load opportunities that we have.

COMMISSIONER PRIDEMORE: And I recognize, Mr. Grubb, that your job in here is to talk to me as if the glass is half full. My job is to ask you that -- about what would happen if the glass is half empty.

And if the glass is half empty and the company has already expended the funds to put CTs into the system, which you said yesterday you think will probably be the last ones the company ever asks for, those are there -- you said that.

MR. GRUBB: No. I said -- when I was asked the question on 45-year lives and how we thought Yates would go 45 years, I said it would be the last ones we would ever retire off the system if we built them. I didn't say they were the last ones we would build.

They -- that question, I think, was Ms. Coyle asking about the 45-year life and it -- or I can't remember if it was Ms. Coyle. Somebody asked about the duration of the facility.

And I made the point that the -- that you're going to have those CTs. And if that's the newest CTs, then you would expect you would get rid of all the other CTs. I didn't say it was the last ones we would ever build.

COMMISSIONER PRIDEMORE: Okay. Let me back up then. Let me make sure.

So it is not your belief that these will be the last CTs that Georgia Power seeks to procure for generation?

MR. GRUBB: So the expansion plans and everything we look at show gas units, whether they're CTs or CCs, being something in the next 10 to 15 years that we need.

COMMISSIONER PRIDEMORE: Will Georgia Power come back to this Commission and seek more gas units to fulfill demand in the future; yes or no?

MR. GRUBB: Yes, if those are the resources that we bid into the capacity RFPs and they're needed to support the reliability for customers.

COMMISSIONER PRIDEMORE: Okay. So your comments yesterday were not that this is the end of gas procurement for generation for Georgia Power?

MR. GRUBB: Right. Again --

COMMISSIONER PRIDEMORE: Okay.

MR. GRUBB: -- we've got to make those -- those are decisions we've got to make down the road. But when you look at expansion plans, gas is part of the -- the future.

COMMISSIONER PRIDEMORE: Okay. All right. So in this docket the company seeks to be able to put the -- the gas generation first because we need dispatchable energy. And so that's procured, but the load does not materialize. The company then comes back to the Commission and says that the load doesn't -- hasn't materialized.

And then what is the company seeking if the load does not materialize; cost recovery on those units?

MR. GRUBB: Right. Those units, though, will help beyond just this time frame. So we have capacity needs when PPAs roll off in the -- the late '20s, as well.

So we've been focused on up through '28 here, but if we deploy those units, they help for multiple years down the road. We've got thousands and thousands of megawatts of need through the 2020s and the 2030s from PP- -- load growth, PPAs rolling out, the eventual retirement of coal units.

Even though we may extend them, we've got to

make that decision. They are -- at some point you're going to have to have some more generation. So it does help from that standpoint.

COMMISSIONER PRIDEMORE: But you recognize that the reason that the cycle that the company and the Commission -- or the state of Georgia uses with the company is there's an integrated resource plan and then there's a rate case?

MR. GRUBB: Yes.

COMMISSIONER PRIDEMORE: It's very -- it's simple in the respect of: We plan, we work through the planning, we pay for what we just initiated. We plan, we work through the planning, we pay for what we just initiated.

That's a system and a cycle that has been since the legislature passed the IRP bill back decades ago. Why would there not be a rate case attached to this one?

MR. GRUBB: Because, again, the -- a lot of the resources don't go into service. The new resources don't go into service in the -- the term of the rate case right now. They don't go in service until after '25. So that's part of it.

And, again, this was not considered in the rate case. This is about a load growth and these

resources. So we're deferring them to the next regulatory cycle in the rate case side, which is getting it back into that process that you mentioned.

COMMISSIONER PRIDEMORE: But going back into the next rate case cycle, you're going to have additional resources that would get procured through this docket being put into that rate case, plus an additional IRP?

MR. GRUBB: So I don't know that the '25 IRP will have resources coming in that early. Usually the IRPs have some --

COMMISSIONER PRIDEMORE: If your load projections and everything that -- that Mr. Valle has been saying happens, why would you -- how could you not?

MR. GRUBB: Well, it -- but it wouldn't be for resources in the -- through '28. It would be for resources beyond that. And so we would have to capture that in the IRP, but --

COMMISSIONER PRIDEMORE: It doesn't matter. The -- you would -- you would still come in in -- in that rate case to be able to seek recovery because it's going to be in the '25 IRP plan.

MR. GRUBB: And that is the cycle and it's

worked well. But the -- the rules and the exceptions are in there for not everything happens on three-year cycles.

So a lot of -- almost all of the resource certifications we have done have been outside of IRPs. RFP certifications, capacity renewables, the -- all but one have been done outside of that three-year cycle. So there's -- there's --

COMMISSIONER PRIDEMORE: But those were approved in an IRP, Mr. Grubb. That's -- that's where I can't --

MR. GRUBB: Not all RFP --

COMMISSIONER PRIDEMORE: This is -- I don't know -- I don't know why I can't get an answer out of you about this. I mean, this is so simple.

There is planning and rate case, planning and a rate case. What we're going to have in '25 is planning, planning, rate case. Two separate planning dockets where the company is going to seek in to procure resources and then we're going to have to pay for it.

MR. GRUBB: So --

COMMISSIONER PRIDEMORE: Is that not the case?

MR. GRUBB: So this -- this is an IRP update for planning to handle the unprecedented changes

that we've seen, which is allowed by the rules and accommodated by the rules.

COMMISSIONER PRIDEMORE: Mr. Grubb, I'm not saying it's not. What I'm saying is, is that when you have two separate planning dockets that have different generation that are -- that is put into those, and then you have a rate case on the backside, somebody has got to pay for it.

And are the share- -- are you saying the shareholders are going to absorb the cost of this planning docket?

MR. GRUBB: No. We --

COMMISSONER McDONALD: We have input into that, Commissioner.

COMMISSIONER PRIDEMORE: Well, we have the decision.

COMMISSONER McDONALD: Right.

COMMISSIONER PRIDEMORE: And the state of Georgia has the decision.

MR. GRUBB: I just --

COMMISSIONER PRIDEMORE: I would like -- I would like to hear the -- the --

COMMISSONER McDONALD: Well, that's --

COMMISSIONER PRIDEMORE: I would like to hear the company say that.

COMMISSONER McDONALD: That's the guarantee that we have for them living up to what they said they are going to do.

COMMISSIONER PRIDEMORE: Which is why I'd like to hear the company say it.

MR. GRUBB: And I'm -- I missed a little bit of what you're --

COMMISSIONER PRIDEMORE: If there's no cost to this, then that -- if there's absolutely definitively no cost to this docket, that changes the nature of the docket.

If the company is saying that they've put forward a pricing model where the customers that are going to be served by the generation of this docket are going to absorb 100 percent of the cost of it no matter what, that changes the whole tone and the necessity of the docket.

MR. GRUBB: So I would -- I would come back to the -- the deferral. And as we've talked about, the deferral -- the reason we're asking for deferring the cost in this case to the next rate case cycle is because the needs for that capacity are in that '26, '27, '28 time frame. So that's why we deferred them.

They -- they weren't taken into account in the

last rate case. So we are trying to put that back on the next regulatory cycle for when those resources are needed.

In terms of the -- these -- I -- was your question: Are these incremental customers paying for these projects? I want to make sure I got the question right.

COMMISSIONER PRIDEMORE: Is there any ratepayer impact at all in Docket No. 55378?

MR. GRUBB: There is --

COMMISSIONER PRIDEMORE: Is it going to cost customers a penny in Docket 55378 for what the company is filing?

MR. GRUBB: There -- there will be increased cost, but there will also be increased revenues that will put downward pressure on rates at the end of the day.

COMMISSIONER PRIDEMORE: Will the ratepayer pay a penny more if -- for Docket 55378?

Increased cost of revenues is a wash. Will the ratepayer pay more for that for this docket?

MR. GRUBB: Do you mean -- do you mean are costs higher or do you mean are their bills higher?

COMMISSIONER PRIDEMORE: Will the ratepayer pay a penny more than they pay today if Docket No. 55378

is passed by this Commission --

MR. GRUBB: We would expect them --

COMMISSIONER PRIDEMORE: -- as the company filed it?

MR. GRUBB: We would expect them to pay less. They will pay less.

COMMISSIONER PRIDEMORE: They will pay less?

MR. GRUBB: They will pay less.

COMMISSIONER PRIDEMORE: Okay. Wow. Thank you.

VICE-CHAIRMAN ECHOLS: I'm following up on that. Do you remember when Southern Company acquired AGL?

MR. GRUBB: Yes.

VICE-CHAIRMAN ECHOLS: Do you remember what happened to the 2016 rate case?

MR. GRUBB: Yeah. I know we didn't have one. I wasn't personally involved in it much, but --

VICE-CHAIRMAN ECHOLS: You agreed not to file a rate case; right?

MR. GRUBB: That's my understanding.

VICE-CHAIRMAN ECHOLS: I would feel a whole lot better about this and give it my full support if I knew that you-all would stipulate: We're not going to file a rate case in 2025.

MR. GRUBB: We're --

VICE-CHAIRMAN ECHOLS: I mean, that would -- that would show me that your leadership believes 100 percent in your estimates and your modeling.

MR. GRUBB: Right.

VICE-CHAIRMAN ECHOLS: And because we're -- we're coming off of a three-tiered rate increase, a natural gas increase, a Vogtle increase. And, I mean, we -- we just can't -- we just can't go back to ratepayers for anything, no matter how confident you are.

And so by agreeing to something -- by stipulating that you won't file a rate case, that gives -- that gives at least me the assurance to know that: Yeah, they really are confident that this is going to -- that this is going to put downward pressure on rates.

Is that something that you-all have talked about?

MR. GRUBB: So this filing will put downward pressures on rates. We are very confident in that. I personally can't tell -- make the decision about the rate case, right, because there are other moving factors in it.

But the -- the resources in this plan and the

loads that they will serve will put downward pressure on rates. And we feel highly confident in these loads and that statement.

VICE-CHAIRMAN ECHOLS: And I'd like to see you-all back that up, you know, with -- with a commitment, you know. And I'm -- I'm excited that our state is growing. I'm excited that you guys are -- you know, have the capability, you know, to -- to move forward.

But -- and we have put great confidence in you, you know, in the past. But this is -- you know, this is just very risky in -- you know, in my view, you know, in -- in going forward.

MR. GRUBB: Yeah. And, Commissioner, I think the flip side of that coin is: I don't know what the other drivers of the rate case are going to look like, but you missed the opportunity to have this level of load growth that gives us the opportunity to put that downward pressure on rates.

I know it's not easy. We know it's not easy.

VICE-CHAIRMAN ECHOLS: But that would also put the pressure on your company that if things fall away and we have, you know -- some, you know, unprecedented world event that happens, that it puts the pressure on your folks to sell that energy, to

get those contracts to -- to be able to do that if you've -- if you've agreed not to come back.

MR. GRUBB: I can't make that decision. I think you know that, but --

VICE-CHAIRMAN ECHOLS: Yeah.

COMMISSONER McDONALD: It does not necessarily mean when a rate case is filed that it is for a rate increase.

MR. GRUBB: That's correct.

COMMISSONER McDONALD: It could be for a rate decrease.

MR. GRUBB: That's correct.

COMMISSONER McDONALD: It could be a rate decrease by this Commission having the authority to measure what you're asking for today at -- in '25. And at that time, it could be adjusted in a band, it could be adjusted in a -- a ROE. There are several mechanisms that this Commission can have the wherewiths and the tools to make those adjustments.

MR. GRUBB: That's correct.

COMMISSONER McDONALD: And -- no, I won't do that.

MR. BAKER: No pressure, Mr. Grubb. No pressure.

MR. GRUBB: That's why we're here.

BY MR. BAKER:

Q A couple of points. I'm going to get completely off the track of what we've been discussing.

Has the company considered, as an option to address this increased capacity demand, a reduction in the reserve margin?

I know that that was brought up in the last IRP by the staff. Would that be something the company would consider at this time?

A (Witness Grubb) No, we have not.

And so, Commissioners, we've actually seen the '26 percent reserve margin serve us very well today and yesterday and last year in Winter Storm Elliott. And I would -- we are redoing the reserve margin study to file the '25 IRP, just like we always do. And we'll capture the lessons learned from Winter Storm Elliott.

We've actually also seen surrounding entities move to seasonal planning and move to higher winter reserving margins, too. So the trend is --

CHAIRMAN SHAW: Who is that?

MR. GRUBB: There's -- I've got a list. It may take me a second to find them. But I know -- I think Duke's moved it up. TVA has moved it up.

I've got a summary here, Commissioner. Just one second.

Yeah, so -- so Duke, TVA have increased theirs. Santee Cooper, MISO. I mean, Duke's at 20, and Duke Florida, and FPL's at 20.

So you see we're still at 26, but you see a lot of people have moved to the 20s that used to be in the 10s. And I believe Oglethorpe and their member entities have increased theirs, as well.

And so, again, 26 percent reserve margin has been absolutely critical to us getting through the cold weather today and -- and last year. So we did not consider it. That's a 2025 IRP item that we always update.

CHAIRMAN SHAW: While we're talking about other utilities, though, what about the 70 percent ownership rule?

Is that pretty common in the industry or is that -- or is that all over the map?

MR. GRUBB: I don't know. You've got different market structures that's not the same as ours, in terms of RTOs. Some groups don't own generation. So I don't know the surrounding entities.

We could reach out to some other companies and see if they've got anything like that. I do believe there are some others that have a percentage of ownership, even on the renewable side, or moving --

if they're doing something for a state plan.

I think in the Carolinas maybe they get to own. But we would have to check into that for you, Commissioner.

VICE-CHAIRMAN ECHOLS: Mr. Grubb, one more thing. 1991, Commissioner Pridemore referenced the IRP legislation.

MR. GRUBB: Uh-huh.

VICE-CHAIRMAN ECHOLS: Three years before he took this seat, right, as commissioner. The reason one of those Scherer units, right, went to Florida for its life is because this Commission denied recovery; is that right?

MR. GRUBB: I wasn't -- I wasn't working with the company then, but I do remember that being the case, that's correct.

VICE-CHAIRMAN ECHOLS: Because of Vogtle 1 and 2, because of the Scherer debacle, the 1991 IRP paradigm shift came into existence --

MR. GRUBB: That's right.

VICE-CHAIRMAN ECHOLS: -- guaranteeing the company recovery -- guaranteeing the company recovery for prudently occurred expenses if this Commission certifies it?

MR. GRUBB: That's correct.

VICE-CHAIRMAN ECHOLS: So our duty is to certify this and put our stamp on this. And --

MR. GRUBB: Yes, sir.

VICE-CHAIRMAN ECHOLS: -- you -- you bring us the plan, we certify it if we believe that it's in the best interest. So we're playing the -- the roles that we -- that we have.

And that's why this is so --

MR. GRUBB: Yes, sir.

VICE-CHAIRMAN ECHOLS: -- important that -- that we get this right.

We -- I respect your -- you know, your forecasting, but it's not perfect. And we -- we want to get this right.

I know that negotiations can be made on this in the future, you know, with our staff, like I mentioned while ago. But we -- we must get this right.

MR. GRUBB: I agree with you a hundred percent on the roles and -- and that is what we're looking to do is get it right, absolutely.

BY MR. BAKER:

Q Another question. Has the company considered -- I think, Mr. Evans, you made a -- a general reference yesterday that the company was able to get the benefit of

500 megawatts of demand response from some of the programs the -- the company had.

Am I correctly stating or you're -- you're --

A (Witness Evans) I think Mr. Grubb referenced that for Winter Storm Elliott, yes.

Q Okay. I'm -- I'm sorry.

A (Witness Evans) Yes.

Q Mr. Grubb, I'll go back to you again.

A (Witness Grubb) Okay.

Q Because of the fact the company's gotten demand response that materialized in the 500 megawatts, based on what you said --

A (Witness Grubb) Right.

Q Something to consider: Would the company consider increasing the demand response -- well, increased demand response by allowing existing customers on RTP to increase the amount of their RTP load?

A (Witness Grubb) So I'll let Mr. Evans help me there a little bit. I mean, there's -- there's a lot of parts to the RTP tariff that I'm not a hundred percent familiar with.

We do forecast RTP price response, though. But the -- the level that's set as firm load versus RTP goes back to the initial contract with that customer and cost recovery, if I'm -- if I'm thinking about that correctly.

A (Witness Evans) Yeah. I think it's important -- you know, you referenced it earlier that the company has put forward several new programs, both through the DER program and the curtailable load program, that will increase, we believe, the amount of demand response or demand -- or these customer-sited programs that can provide benefit to the resource plan.

Through the curtailable load rider, we believe that that's going to provide much firmer response from demand response for CNI customers. And to the DER program, while it is a -- going to be certified as a supply-side program and supply-side resources, those customer-sited programs allow customers with resiliency needs and resiliency backup generation to provide that capacity value, make it available to the company and provide benefits on the resource ledger.

So I think we've -- we've expanded our options there and really looked at a lot of different ways that customers can provide resources value.

MR. BAKER: Thank you, Mr. Evans.

Thank you, gentlemen, for your time today.

Thank you, Commissioners.

CHAIRMAN SHAW: Thank you, Mr. Baker.

MR. GRUBB: Thank you.

CHAIRMAN SHAW: Panel, do you guys need a break

or are you good to move on?

MR. GRUBB: I think we're good. I don't even know what time it is. So I don't bring a watch up here, but I'm good.

CHAIRMAN SHAW: All right. Sierra Club.

MS. ARIZA: Thank you.

CROSS-EXAMINATION

BY MS. ARIZA:

Q Good morning, Commissioners. Good morning, panel. My name is Isabella Ariza. I represent the Sierra Club in this proceeding.

A (Witness Grubb) How do you say your last name again?

Q Ariza.

A (Witness Grubb) Ariza. Okay. I just wanted to make sure if I need to use it.

A (Witness Evans) Good morning.

A (Witness Grubb) Good morning.

Q Good morning.

Other parties have asked many of my questions so all I'm left with is a bunch of follow-ups.

A (Witness Grubb) Okay.

Q Regarding the RFP on page 29 of your testimony, lines 18 through 20, you state that Georgia Power must develop new resources in addition to procuring resources

through the typical RFP process; correct?

A (Witness Grubb) Yeah. Let me -- let me make sure I'm looking at the question up-front real quick. Sorry.

You said 18?

Q Yes -- no. Page 29, lines 18 --

A (Witness Grubb) Yeah. Line 18. I'm sorry.

Q Okay.

A (Witness Grubb) Yes, must develop new resources in accordance, that's correct.

Q Isn't it true that if you over-procure fossil resources now, there's a risk that the All-Source RFP approved in the 2022 IRP will become obsolete?

A (Witness Grubb) No. When you look at the amount of needs we have in '29, '30, and '31, there's -- there's thousands and thousands of megawatts of need. So, no, that -- that RFP will have to go forward.

Q Regardless?

A (Witness Grubb) Regardless.

Q Okay. And, now, regarding the CTs, yesterday in your summary you stated that you will request a certificate of public convenience and necessity for resources like the eight CTs.

Did I understand that correctly?

A (Witness Grubb) That's correct.

Q Will that request be part of this IRP or will it be in a different proceeding after that?

A (Witness Grubb) Yeah, it will be really soon. We -- we filed the contract Friday. And so we're putting that certification together now.

Q Okay. Thank you.

And I believe you told Ms. Whitfield yesterday and Mr. Baker just now that if you build all the resources you've requested, but only some of the demand materializes, then revenue will still outpace the revenue requirement; correct?

A (Witness Grubb) Yeah. What I was comparing there was the -- the amount of revenues is based on a lower load forecast than the one we're asking for in the IRP.

Q But it's true that you'd expect that downward pressure on rates to be greater if you don't significantly overbuild; correct?

A (Witness Grubb) So I wouldn't say we're overbuilding. But if you reduce the resources and, yes, that helps on the cost side, but you can't support the load level.

And so when we price these offers to customers, we're making sure that we're recovering all their costs. And so you miss that opportunity to put further downward

pressure on rates.

Q Okay. You've stated in discovery that you'll run the CTs on oil during peak winter periods; correct?

A (Witness Grubb) That's right. We -- we expect to on peak periods, like today. But it has the ability to burn natural gas in many other hours.

Q Are winter peak periods when you plan to run these units the most?

A (Witness Grubb) So they're -- they're not expected to have super high capacity factors because of the natures of CTs. That is when they will most be needed.

And so these are the most efficient CTs that we would have on the system. And so the -- they'd be the first ones to dispatch. They're -- they're the most efficient ones. They're going to be well-controlled machines.

But, yeah, we would -- on days like today where we're in the peak, we would expect to be running them.

Q They will run before other Yates CTs?

A (Witness Grubb) So there aren't any other Yate-- CTs at Yates. What I was --

Q Okay.

A (Witness Grubb) -- mentioning yesterday was there are some steam conversion units at Yates that have

a -- have a higher heat rate than these CTs will. So all else equal, if you only need a certain set of the units, you would run the CTs versus the Yates CTs.

Q So you could presumably use the firm transportation that you have for the other units --

A (Witness Grubb) Same units.

Q -- at CTs? Yeah.

A (Witness Grubb) Yes.

Q Not CTs.

A (Witness Grubb) Yes.

Q The other units at Yates to power the CTs?

A (Witness Grubb) And we could also have -- release gas from other areas on the system, too.

Q Okay. Thank you.

And you said they'll have a low capacity factor. Is it a 25 percent capacity factor? I think I read that.

A (Witness Grubb) I think that was in our expansion plan we limit CTs to 25 percent. I can't remember what the error permit we'll -- we'll look at.

But, yeah, most of our CTs don't run in the double digits. These may run a little more because they will be the most efficient ones and they can replace generation from, like, Yates 6 and 7. But you're not talking anything in the 70s and 80s. You're talking

about in the teens or lower.

Q Okay. And I think I would like to ask you about that capacity factor because it will impact whether you're complying with Section 111 rules.

So you might recall that in your response to PIA 7-5 you stated that the CTs would be expected to comply with Section 111 rules and that Georgia Power doesn't anticipate any changes impacting the decision to request these resources.

Do you recall that?

A (Witness Grubb) Yeah. Do you have a copy of the DR? I don't -- I don't have them with me, so...

Q Yes.

A (Witness Grubb) There -- there's been a lot of them, so...

Q Okay.

MS. ARIZA: I'm not marking this.

BY MS. ARIZA:

Q So do you see the paragraph that starts: For the proposed combustion turbines at Plant Yates, Georgia Power expects to comply with the 111 rule and does not anticipate any changes impacting it?

A (Witness Grubb) Yes. That is correct.

Q However, isn't it true that EPA's Section 111 rules, if they do go final, the new CTs would have to

either reduce the capacity factor to less than 20 percent or cofire with hydrogen?

A (Witness Grubb) And I think that's the 20 percent capacity factor that we feel is the -- the way we would comply with that.

Q That's how you would comply; reducing it to less than 20 percent?

A (Witness Grubb) Right.

Q Are you taking any specific measures to pursue either of -- or to pursue that path?

Have you quantified how much less you would have to run it, whether it's still economic to build them if you need to reduce --

A (Witness Grubb) We haven't modeled anything on 111. I'd have to look at our economic analysis on what it ran. But I do not believe it would run more than 20 percent in our models. It's not even -- I think it's -- it's less than 20 percent.

Q But you were planning to operate these brand-new CTs at a 25 percent capacity factor?

A (Witness Grubb) No. What I was -- when I mentioned the 25 percent capacity factor is we limit our expansion plan modeling to a CT to that nature, just in case the model tries to run it more than that because we know we wouldn't.

So I didn't -- I didn't say we would -- would expect Yates to all -- be at 25 percent. We think it would be lower than that.

Q Okay. If and when the Section 111 rules become final, they won't just impact Yates. They will also impact existing coal units; correct?

A (Witness Grubb) That's correct. I -- I believe the -- this summer should be the rule. I think it impacts new units, whatever is filed this summer, but then the state plans have to be developed and then follow the -- whatever legal course there may be. But, yes.

Q How do you plan to comply with Section 111 at each of your remaining coal units?

A (Witness Grubb) So, Commissioners, because that rule has not been finalized, a state plan has not been developed and we don't know what kind of legal challenges would result and what the final rule will be. We haven't put together plans on how to comply with 111.

In the '25 IRP update, based on whatever that final rule is this summer, we would -- we would address it in the '25 IRP.

Q Okay. Are you aware that for coal units that you'll plan to retire before 2035, you'll need to operate them at a 20 percent or less capacity factor and not exceed current emissions?

A (Witness Grubb) As -- in the proposed rule. I --

Q In the proposed rule.

A (Witness Grubb) Subject to check, but I remember something along those lines, yes.

Q Okay. On page 10, lines 7 through 9 of your direct, you state that the resources you're planning to procure contribute to the continued transition of your generation fleet to cleaner resources; correct?

A (Witness Grubb) That's correct.

Q Isn't it true that to properly provide that foundation and that transition to cleaner resources, you need to start committing now and not in the 2025 IRP to retire your remaining coal units?

A (Witness Grubb) No.

What we're talking about here, Commissioners, is the way we've transitioned the fleet has been working with this Commission and making sure that we do it in a reliable and economic way to move forward with that. In working with this Commission, we've -- we've achieved over 60 percent carbon emission reduction since 2007.

And so when we talk about this plan, we look at the fact that the PPAs are -- are done by the end of 2028. Battery energy storage systems are a big part of the fleet transition and then CTs are, as well. So when

we look at our expansion plans that handle a range of carbon pressures, it -- it does select CTs and CCs as part of the future fleet. So this plan, the resources we're asking for here, are supported by that.

Q And how about coal retirements?

A (Witness Grubb) So those will be addressed in the 2025 IRP.

Q So it's your testimony that proposing coal retirements in the 2025 IRP will still give you enough time to procure replacement resources you'll need?

A (Witness Grubb) So those -- the Scherer and Gaston have been approved to be decertified in the '28. If we need to change that, then that will be brought forward to the Commission in the 2025 IRP.

So we haven't planned for those coal -- they don't show extensions in our needs. And so it's going to depend on what comes out of the 2025 IRP what we would need to do there. But we will work with the Commission on that.

Q Okay. Thank you.

On page 27, lines 24 through 26 of your direct, you talk about the 1,000 megawatts of battery storage that you plan to own and operate?

A Yes. That's correct.

Q First, I've heard you say that if load doesn't

materialize you could choose to not build as many battery megawatts or you could choose to resell capacity attached to the PPAs. But I haven't heard you say that you could choose not to build three, but two CTs, for example.

Isn't it true that that is a possibility, as well?

A (Witness Grubb) It is. Except that we -- we see the need for CTs because, again, the expansion plans support that and you need dispatchable resources as part of the mix going forward.

And so CTs are complementary to solar and storage. They provide capacity when -- when it's most needed. And because we've identified those CTs, the reason we've mentioned batteries is we haven't specifically identified the additional batteries yet. So we would continue to move forward with the Robins and Moody's and the CTs.

Q That was going to be my next question. Is Georgia Power willing to commit to building the full 1,000 megawatts of battery storage?

A (Witness Grubb) That is the plan right now. To our prior discussions with the Commission, if we don't need them, we would not.

Q Okay. I have some questions on the flex capacity framework.

A (Witness Grubb) Okay.

Q On page 50, lines 19 to 21, you describe it as a framework to acquire additional capacity ahead of the '25 IRP if an updated load forecast projects additional needs; correct?

A (Witness Grubb) That's right.

Q And you also state that you would request Commission approval before procuring additional capacity; correct?

A (Witness Grubb) Yes.

Q Do you expect parties to be able to intervene in that flex capacity approval process as they do in the regular IRP?

A (Witness Grubb) Yeah. If we bring things to the Commission for certification, parties partake in that just like we are here.

Q Okay. Thank you.

What types of assets are you thinking about acquiring to fill this emergent need under the flex capacity framework; like a PPA, for example?

A (Witness Grubb) So it would most likely be energy storage systems because we -- we could build those a little quicker. It could be an existing PPA if -- or there could be a PPA if we had an existing resource that we could contract with. We're not aware of any.

But if -- if we -- if someone had one that we weren't aware of, we could approach them. But it would most likely still need to be something you could deploy quickly. So it would be battery energy storage systems at a location similar to Robins and Moody's where you don't have to build transmission for delivery.

Q Okay. And something like the Southern Company asset, would that -- could you be able to acquire that through the flex capacity framework or have those negotiations failed permanently?

A (Witness Grubb) There are no ongoing negotiations on that.

Q To be clear, you need to file your 2025 IRP by January 31st, 2025; is that right?

A (Witness Grubb) We are required to file it by January 31st of 2025.

Q And the flex capacity framework would allow you to seek approval for the time between this IRP that ends in April and January?

A (Witness Grubb) Yeah. If -- if, as Mr. Valle has talked about, you've got a lot of economic potential in the pipeline. If we were to win some jobs that were really large that drove that need up, that's correct.

Q How far in advance do big industrial customers usually approach you to let you know that they will need

to connect to the grid?

A (Witness Valle) So it -- it depends on the ramp-up. So the -- the timing for when the load is going to be served, it's -- it depends on the -- on the ramping assumptions for -- for each customer.

So it could be a couple of years, it could be five, it could be ten. It really depends on each customer.

Q Probably not less than two years; is that correct?

A (Witness Valle) I would say yes.

Q Okay. And, for example, when did you first -- when were you first approached by a data center to get them online?

A (Witness Evans) When were we first -- could -- any data center?

A (Witness Grubb) By -- by any data center?

Q In the last -- in -- 2022 onward?

A (Witness Valle) So the first data center that approached us -- the larger one; right?

Because we -- we currently serve about 62 smaller data centers. But the large hyperscalers, the first one was after the 2022 IRP load forecast was finished, was about December of 20- --

A (Witness Grubb) Two.

A (Witness Valle) -- 22.

Q Okay.

A (Witness Valle) 2021.

Q 2021?

A (Witness Valle) '21. I'm sorry.

Q Okay. Thank you.

I have some questions on the Mississippi Power PPA.

A (Witness Grubb) Okay.

Q On page 32 of your testimony, you link to the Mississippi Power ordering Docket No. 2018-AD-145. And it's come up several times already in this hearing.

A (Witness Grubb) Yes.

Q In that order, the Mississippi Public Service Commission instructed Mississippi Power to retire their Daniel coal plant by the end of 2027, unless the company provided detailed evidence explaining why the continued operation is in the best interest of its customers; correct?

A (Witness Grubb) That is -- yes, that is correct.

Q Are you aware whether Mississippi Power has, in fact, demonstrated to the Mississippi Public Service Commission that continued operation of Plant Daniel is in the best interest of its customers?

A (Witness Grubb) I -- I don't know the specifics on Mississippi's communications with their commission. The PPA is not tied to any specific unit. And so it's up to Mississippi there, but I would -- I would think they would have at least given them a heads-up on the PPA, but I don't know the specific details of the conversations.

Q Are you aware that the Mississippi Public Service Commission found that Plant Daniel would be expected to impose net costs on Mississippi Power customers?

A (Witness Grubb) I'll take you at your word. I -- I haven't been involved in that in Mississippi.

Q So Georgia Power is not taking any of that risk?

A (Witness Grubb) And that risk being the cost risk?

Q Yes.

A (Witness Grubb) No. So what we've got is a PPA from the Mississippi system with contracted prices at market prices and it's not tied to any specific unit.

Q Does the PPA cost reflect environmental upgrades that could be needed to retrofit Plant Daniel?

A (Witness Grubb) So, again, that -- that PPA pricing was set on market -- expected market pricing for that type of a sale. I don't know how Mississippi does

their cost recovery, but it's not unit specific in the contract.

Q Did Georgia Power evaluate purchasing power from Mississippi Power, other than capacity associated with Plant Daniel?

A (Witness Grubb) Ask the question again.

Q Did you consider purchasing power from Mississippi that was separate from the Daniel coal plant?

Did you consider telling them: Please give me power from these resources, but not this one?

A (Witness Grubb) No, we did not. I mean, again, we're -- we're -- the contract was to make sure that that 750 megawatts remained in the Southern Company pool. And so we -- it -- we aren't driving Mississippi to make any specific decision of what they want to put in there. It's -- it's a system sale.

So it's really the same system, like we've talked about reserve sharing, just trying to make sure we've got that -- those resources in the pool for those five years.

Q And, to confirm, all of those 750 megawatts are coming from fossil fuels?

None of it is from clean resources; right?

A (Witness Grubb) I don't -- I can't recall what Mississippi's total fleet mix is. Because, again, it's

just from their fleet. They do have some solar, but I'm not sure what their percentage is.

Q So -- but it could be solar?

A (Witness Grubb) Well, we're -- we're not -- we're just getting pool dispatched energy from the system and 750 megawatts to make sure those -- that there is 750 megawatts in the pool.

Q And you said before that you don't know what the total Mississippi Power pool is?

A (Witness Grubb) I mean, I have a general representation, but I don't --

Q Okay.

A (Witness Grubb) I don't have a -- an exact number.

Q Maybe the general knowledge that you have will be enough to answer this. But if Mississippi -- the Mississippi Public Service Commission ultimately orders Mississippi Power to retire Plant Daniel early, will -- will you need to line up other alternatives or will Mississippi Power --

A (Witness Grubb) It depends on how Mississippi treats the PPA. And so if -- if they can back up the 750 megawatts, then nothing would need to change.

Q Okay. And some final questions. You didn't file an environmental compliance strategy as part of this

IRP; correct?

A (Witness Grubb) That's correct. But we file one every year with the Commission.

Q So is the prior environmental compliance strategy still good?

Is that the one that we should reference?

A (Witness Grubb) Yeah. We usually file it early in the calendar year. I'm a little rusty on which date, but we usually file it in, I think, January or February with the Commission.

Q Okay. Are you aware that on March 2023, EPA published a revision to the ELG rule that would require enhanced wastewater treatment beyond what you're currently planning to install at your coal plants?

A (Witness Grubb) Yes. Relatively familiar with it, yes.

Q Okay. Have you quantified how much it will cost Georgia Power to install those additional controls?

A (Witness Grubb) We have not. The rule is not final yet. And, again, that would be something that would be addressed in the 2025 IRP on those units.

MS. ARIZA: Okay. Thank you. No further questions.

MR. GRUBB: Thank you, Ms. Ariza.

MR. VALLE: Thank you.

VICE-CHAIRMAN ECHOLS: Mr. Grubb, on that Mississippi PPA, will they pay liquidated damages if they don't produce the 750?

MR. GRUBB: I would have to go back and look, Commissioner, on that. Again, it's really just the Southern operating pool. So they have every incent to have those resources available and online. I can't remember if -- if there are damages or not. I would have to go back and look.

CHAIRMAN SHAW: Mr. Jacob, do you have any indication or idea on how long your cross might take? I'm just trying to plan for lunch.

MR. JACOB: Twenty minutes.

CHAIRMAN SHAW: Let's go ahead and -- let's go ahead and do it. Come on up.

CROSS-EXAMINATION

BY MR. JACOB:

Q Good morning still. Brian Jacob with Southern Alliance for Clean Energy.

And while this one's still fresh in my mind from that conversation you just had with Ms. Ariza, when -- when you're talking about the Mississippi Power PPA, and it's -- it's a capacity PPA and not an energy PPA, but will we always be getting megawatt hours off of it, as well, or do you only get megawatts when you need

them?

A (Witness Grubb) No, you get megawatts hours, as well. But it's -- it really is just serving the pool; right?

So those -- those units are going to be dispatched at -- in the Southern Company pool just like they are today and -- as part of the pool. And so that energy payment is just going to be handled through the pool because it's just energy.

And it's just pool transactions. And there's no unit specific. So it's not a fuel price off a specific unit. It's basically the -- the pool rate. And then the megawatts are -- are serving Georgia Power.

Q So is that how you were saying that there was the possibility that it could be served by solar like during, you know, an afternoon; whereas, what's really driving the need for that is these winter mornings when even if they have solar in the Mississippi Power portfolio, it wouldn't be generating on those winter mornings?

A (Witness Grubb) It's -- we're just getting energy and capacity from the pool. And so we have the PPA. So, again, when we look at that, those resources are going to leave the pool, either through retirement or to be sold elsewhere. We needed those megawatts to stay

in the pool and so we got a PPA.

So those megawatts are what we're going to pay for. And it's from their system. So it -- it's just dispatched price is what we'll get. And they'll just help serve the load of the whole pool.

Q All right. Let's see. I also was a little confused yesterday from your conversation with Mr. Carver, so I want to actually start there.

As a result of the 2019 IRP -- so going way back -- you issued what was called the 2023-2024 utility-scale renewable RFP for 1,030 megawatts; right?

A (Witness Grubb) Subject to check. But, yes, that sounds right.

Q Okay. Were any contracts executed through that RFP process?

A So from the first part of 2019 IRP, my recollection is, yes, there were.

Q Of the 1,030?

A (Witness Grubb) Yeah. You're talking about '19?

Q Well, now, this was the 2023-2024 RFP that came out of the 2019 IRP.

A (Witness Grubb) Yeah. I -- I believe we did fill that one, subject to check. I mean, we've -- we've got the two from the -- I have to back up.

Q My understanding was you did the 970 megawatt first.

A (Witness Grubb) Right. That's the first one.

Q And then the excess from that got carried over and you issued an RFP for 1,030?

A (Witness Grubb) Well, it -- yeah. Well, it's carried over into the ones we're doing now.

Q Yeah. And you brought that up yesterday, too.

But -- so it got carried forward into the CARES RFP?

A (Witness Grubb) Correct.

Q Why did you have to carry it forward if there were contracts from it?

Let me start there.

A (Witness Grubb) There were -- there were -- we did two RFPs --

Q Right.

A (Witness Grubb) -- coming out of 2019. So the second one is the one that didn't have any contracts come out of it.

Q Yeah. That's the one I was asking about.

A (Witness Grubb) And that's what we've deferred. Because, again, you've got to go through the RFP process. And so we rolled it into the CARES subscription, which is adding to what we got approved in the '22 IRP. And we've

done that traditionally with DG and some of the others.

Q But the CARES RFP has different time frames on it than the original 2023-24?

A (Witness Grubb) That's correct. And because those resources weren't able to be contracted, we've got to -- you roll it out because you've just lost two years. So you've got to go back through the RFP process.

So physically bringing them online for those CODs wasn't achievable. So we just rolled it over to the next one.

Q So reflecting back on the bids, though, were any of those bids capable of being online by the winter of 2025-26?

A (Witness Grubb) you're talking about the second RFP in which --

Q The second one.

A (Witness Grubb) -- we didn't do contracts?

Well, I -- I believe they were -- they were not contracted because of the requirements in the RFP. So it doesn't matter if they -- they couldn't meet the requirements of the RFP.

Q I know that's why it -- they didn't get contracted, but Mr. Bush said yesterday that you circled back to existing solar sites to gauge their potential to host battery storage.

Did you circle back with any of those bidders to -- who could have been online by November of 2024, which was the requirement of that RFP, in order to see if they could contribute to this new unanticipated load?

A (Witness Grubb) No. We were -- we were reaching out to people who have existing solar facilities now. So those -- those were not contracted, weren't built, aren't online, so we did not approach them.

Q If they had the potential to be online by 20-- by the winter of '25-'26, why would not circle back and -- and put those into the -- the potential mix for this IRP?

A (Witness Grubb) Because we were focused on ones that already have points of interconnection that are on the system that we can use to put the storage on. So we need physically built interconnections is what we're targeting right now as the priority.

Q All right. Let's see. Moving on. I have -- a lot of questions have been asked and answered so I'm trying to slim mine down.

Several times you've said that 17,000 megawatts of large load -- that there is 17,000 megawatts of large load in the pipeline and it's increasing.

What is the time horizon on that? Is that all by 2028?

A (Witness Valle) No. That -- that load materializes over time. It's -- I would say it materialize into the mid '30s.

Q Okay. So not all of that is driving this immediate need that you're asking for in this update?

A (Witness Grubb) Yeah. No, we've been -- we've been clear. I hope we've been clear that we're not asking for all 17,000 megawatts.

And so the ones we are projecting are the ones that are closer to being able to come online and -- and that load that we see by the end of '28.

Q Okay. Well, so -- so my understanding of your probability discussion yesterday, and even today, was that it's -- that you've used a probability analysis against that 17,000 megawatts to decide what to ask for.

Now I'm hearing you say that -- that it's more time sensitive. You're asking for a portion of the 17,000 that represents the need between now and 2028. And you could potentially ask for the rest of the 17,000 later.

A (Witness Grubb) No. So the load forecast is not 17,000. So Mr. Valle can jump in here. What I was saying when -- we did that analysis on the forecast, which we mentioned this morning was around 7,000 megawatts. Those details are what we put into our

planning and that's the -- what's driving the capacity need.

So it's not -- it's something in the 30s. And we have ramp rates. It's not like everything hits immediately. So it's a combination of all those different factors.

A (Witness Valle) Exactly.

Q How many megawatts of large-load demand is in the pipeline between now and 2028?

A (Witness Grubb) Well, I don't know that -- I don't know that.

A (Witness Valle) I don't know if I have that data in front of me, but we -- it ramps up in -- into it, so...

Q Okay. It seems like to me that's the -- that North Star we ought to be talking about, rather than 17,000, which is misleading if it's -- because we can take that up in the 2025 IRP. We don't have to deal with the rest of it now. There's a lead-in.

A (Witness Valle) I think it's important to know the size of the portfolio of load that we -- that we have; right? So that's what we're planning for.

How it materializes over time, how that matches within the existing resources and the new resources, that is also part of the consideration and part of the

planning process.

So, first, identify the load. Second -- you know, the load and the timing. And then, second, to plan for the resources to serve that load.

Q Okay. You list a number of the different -- of business categories on page 14 of your prefiled testimony: Warehouse, battery manufacturing, cryptocurrency data centers, chemical processing.

A (Witness Valle) Can you please point me to the line?

A (Witness Grubb) Which line?

Q Yeah. It was lines 9 through 11 is where you list the categories.

A (Witness Valle) Thank you.

Q I just want to clarify that from yesterday you answered a question from Chairman Shaw of -- actually, both you, Mr. Grubb and Mr. Valle, about data centers.

And, Mr. Grubb, I think you said it's greater than 50 percent. And, Mr. Valle, I think you indicated that it's 80 percent, which can be consistent. It is more than 50.

A (Witness Grubb) I didn't know the details so that's why --

Q Yeah.

A (Witness Grubb) It was greater than 50, which

was right. It was 80.

Q So data centers represent 80 percent?

A (Witness Valle) A large portion, yes. Closer -- not 80, but around.

Q How much do the other categories represent?

A (Witness Grubb) Of these?

Q Well, individually. What's the next highest contributor on that list?

A (Witness Valle) I would say -- I would say battery manufacturing and --

A (Witness Grubb) Industrial.

A (Witness Valle) -- the industrial category.

Q Okay. You separate out data centers that are used for cryptocurrency mining. But did I hear you say that you do not separate out those that are used for artificial intelligence?

A (Witness Valle) No. So the data centers fall -- all of the data centers fall into one single category and we treat them -- we treat them all the same from a forecast perspective.

Q But you don't consider cryptocurrency mining to be a data center?

A (Witness Valle) They are types of data centers and they behave just like other data centers in the sense that they use energy 24/7. And -- and, you know, the

purpose of the operations is different, but essentially they are data centers.

Q Since you listed it separately in that question, that's why I was asking. You list cryptocurrency, comma, data center, comma, chemical processing.

A (Witness Valle) Yeah. It's important to give some -- some distinction to it to provide some -- some, you know, background to the description of the portfolio of large load. But in itself it doesn't -- it doesn't have an impact on the load.

Q So when you said that the data centers represent 80 percent, is that inclusive of cryptocurrency or exclusive?

A (Witness Grubb) We just know there's more questions around those. So we wanted to note that there are some in the data centers, but it's not the majority.

Q I understand. So -- let's see. I want to reiterate -- Commissioner Pridemore made a hearing request about that yesterday. About how much cryptocurrency contributes. I would like to reiterate that SACE would like to see that, too, when you file that.

A (Witness Grubb) Okay.

Q Cryptocurrency miners have helped the Texas

grid maintain reliability during recent winter storms. They've been able to go offline when absolutely necessary. And you've got the curtailable load program that you proposed in this IRP update, but it's optional.

And so what makes you think that enough of them will participate voluntarily to make a difference?

A (Witness Evans) Well, a couple of things there. One, a portion of the customer load will be served through marginal price and RTP, which price signals are sent to the customers, like we did today, during reliability concerns. Which they are sent a very strong signal to curtail their load based on that pricing.

For the embedded portion of their load that's served on a standard rate, that portion can be served through a curtailable load. And customers with flexible operations will receive a strong incentive there through that program to further curb their load, to the extent that they're flexible and they can.

Q Separately in your testimony -- it's page 18, line 27, if you want to look it up. You say that the company develops a probability analysis for each point of uncertainty in the model.

So where are those individual probabilities disclosed?

A (Witness Valle) Where in the filing?

Q Yeah. Were they in the filing or are they in a data request or have they not even been disclosed?

A (Witness Valle) They're listed in the -- in the technical appendix for the load forecast, yes.

Q All right.

A (Witness Grubb) It's trade secret, but they're in the technical appendix with the original filing.

Q Is the cryptocurrency miners' participation in the curtailable load program one of those points of uncertainty?

A (Witness Grubb) No.

A (Witness Valle) No.

A (Witness Evans) And, again, that's an optional program; right? So it has customers enroll in that and that capacity value will be reflected on the resource ledger. We can't project what that participation will be right now.

Q You do probabilities on lots of other things that are uncertain. Why could you not run probabilities on the adoption rate of that program?

A (Witness Valle) Because that one doesn't impact the load that we need to serve.

A (Witness Evans) It also hasn't been approved. So it's not an actual program we can offer customers right now.

Q I struggle with that last answer, Mr. Valle. Because it doesn't impact the load that you have to serve?

It seems like it's intended to do that.

A (Witness Valle) No. Because -- so because there are certain elements of uncertainty that we have captured into -- into our evaluation; right? And so the fact that you have different operations, the fact that there may be some future customer behaviors, that is -- that is yet to be determined.

But with the information that we have today available, we have incorporated the elements that are reasonable to -- to do so.

A (Witness Evans) And I -- to add on to that, if once the curtailable load program is approved and we work with customers on developing what rates they'll take service under and things like that, to the extent they have load flexibility and would like to enroll in a program in which they're eligible, we'll reflect that and then model it in both the resource plan and our loads that we would -- that we would need to going forward.

So to the extent customers are going to enroll and participate in these programs, we're going to reflect that.

VICE-CHAIRMAN ECHOLS: Every crypto miner that

I've met with and talked to, they like the interruptible rate. And I haven't -- in fact, I haven't met a single one that said: No, no. We need it 24/7 just like a regular data center.

Has your experience been different?

MR. EVANS: Not necessarily. And I think we see -- we should see some response to RTP from those customers like that that have that highly flexible operations; right?

MR. GRUBB: And we would -- and we would model it and include it as a demand-response asset. So it's not a load reduction, in terms of the load forecast for the crypto mining, but it reduces the demand response to lower the need of that load. It's serving for that load in our plans.

MR. EVANS: That's right. Unlike things like energy efficiency, where it's a change in the reduction to the load forecast itself, Mr. Valle will show the actual load. But to the extent they enroll in a demand-response program, like the curtailable load program, that will actually be reflected on the resource side of the ledger. Not as a reduction to load, but actually as a resource to meet the load because it is dispatchable.

BY MR. JACOB:

Q How many megawatts of resource did you consider on that side of the ledger in this request that you're putting forward to the Commission right now?

A (Witness Evans) We have --

A (Witness Grubb) You're talking --

Q The curtailable load, how much is it going to serve?

A (Witness Grubb) We haven't done that yet because we don't know which customers are going to sign up to it and if it's going to be approved.

Q So if it's approved and it's wildly successfully, will it reduce the amount of generation resource that you're asking the Commission to approve?

A (Witness Grubb) It would help meet those needs that we talked about in '28. And so it would help meet the needs. And we would adjust the plan once we knew it.

But we don't know it yet, so we can't -- we can't pause the resources we need to develop here. So there's something that comes in and helps with that, but we can't plan on it right now and not move forward with the other resources because then we wouldn't be able to serve load. So we will adjust the plans as they're -- as those programs are certified and subscribed to.

Q All right. On page 20 you express that there's a limited amount of electric generation capacity

available in the wholesale market. And then you say something similar on page 22, that existing market resources are not sufficient to address the capacity need identified in the 2023 IRP Update.

A (Witness Grubb) That's correct.

Q But Georgia doesn't participate in organized market like a regional transmission organization; right?

A (Witness Grubb) No, we do not. We don't have an RTO here, but what we're pointing to is that there are no -- to be able to meet these time frames, facilities have to be existing, if they're not company-owned from a timing standpoint.

Q Would participation in a robust, organized wholesale market increase the likelihood of having more resources available like this in the future?

A (Witness Grubb) No. Because I don't know that people are just going to speculatively build generation and sit there and hope. Most of the people either have something that was responsive to a prior RFP that has come out of other contract or they're building it for a future RFP.

So I don't -- I don't know that that -- a change in that would result in resources being on the ground and able for us to go get them.

Q Okay. Also on page 20 you say: Any new-build

resources selected through such an RFP would need to be constructed within one year to meet the capacity needs.

How long does it take to install a reciprocating engine?

A (Witness Evans) Can you point us to a line number?

Q Line 20 to 22.

A (Witness Grubb) Page?

Q Page 20, lines 20 to 22.

It's a one-year time frame there, it looks like.

A (Witness Grubb) Yes. For line 21, right.

Q So how long does it take to install a reciprocating engine?

A (Witness Bush) It does sound like we have a little confusion here, Commissioners. There's many components to ensuring that we deliver power to our customers.

One of the most significant components is ensuring we have transmission. Not just the ability to interconnect to the transmission system, which we expect will take between three and four years normally. But, also, once you're interconnected, to be able to reliably and firmly deliver to our customers.

So while I can build a reciprocating engine,

construct one in a short amount of time, like a battery, I can just go through -- like I mentioned yesterday, we've actually constructed the Mossy Branch battery in nine months.

I have to have deliverability. And that's a huge component of the timing behind what it takes to ensure we serve our customers reliably.

Q You do have experience with the Wartsila RICE engines; right?

A (Witness Bush) Yes. We have some experience with Wartsila.

Q Were those considered as alternatives to the combustion turbines you're proposing at Plant Yates?

A (Witness Bush) Not specifically for Plant Yates, no.

A (Witness Grubb) Commissioners, I would add, too, that we look at our expansion plan that looks at predominant resource solutions through the next several years. Reciprocating engines were not picked. It was battery storage and combustion turbines.

Q Weren't picked by the model or was the model allowed to select RICE?

A Witness Grubb) They were allowed to select them and did not pick them.

Q So regarding existing resources that are out

there and available, how did you decide which ones to negotiate for?

A (Witness Grubb) So as I've identified, we went to the system length first because we knew Mississippi had some. And then we reached out to those that we had had prior experience with.

So we reached out to a few. Some were not able to be able to -- like Lindsay Hill, as we mentioned in the DR, could not be available in this time frame. So it was based on the ones we had had contact with. And we've got wholesale marketers that know the participants, but -- so we reached out to the ones that we were aware of to see if they had contracts.

But a lot of them had either been purchased by us already through PPAs that were approved in the 2022 IRP. And as we mentioned yesterday, Oglethorpe had purchased a lot of them. So we went to the ones that we -- that we knew.

Q It's well documented that Jackson Electric already wants out of their PPA with MEAG for outlet from Vogtle 3 and 4. Did you consider relieving JEA of that Vogtle obligation and keeping that dispatchable, carbon-free energy for Georgia Power customers?

A (Witness Grubb) We have not.

Q Why?

A (Witness Grubb) I don't know what the cost of the economics are. And I don't know -- I don't have any day-to-day with JEA.

So we did not approach them, just from the standpoint of -- I wasn't aware of that. And so we just didn't. I don't know what JEA is looking to do out of Vogtle.

Q If you considered some of the potential options that are out there, but not all of them, how can this Commission be sure that the ones that you're putting forward are the best portfolio options?

A (Witness Grubb) Are you asking about the market ones?

Q The entire IRP. I just -- the reason I wanted to ask questions about some of the other things that I know could have been options and you didn't pursue, I just want to know how the Commission can be confident that what you're asking them to approve is the best set of options?

A (Witness Grubb) Right. So we, again, went to the system length. We went to the market resource that was able to be available in that time frame. The RFI indicated no existing market resources that were available in that time frame.

And so then we moved towards deployment.

Again, the future fleet needs batteries and CTs. And so we exhausted the market resources we had access to and then moved to construction of the ones that we could deploy in this time frame.

Q Okay. Let's see. Something else from yesterday, Mr. Grubb, on transmission. I believe you said that the transmission requests that are in this IRP are exclusively for the CTs at Plant Yates?

A (Witness Grubb) So, yeah, we identified the transmission resources needed to support the resources. And Robins and Moody's and the PPAs do not need transmission projects built to support them. Only Yates does. So that's the request.

Q And that was based on initial screening, but you've got a more formal analysis going on right now?

A (Witness Grubb) That we will provide this month that identifies those same projects, but at a lower cost than we had at the initial filing. That will be filed this month.

Q I was going to ask if you could preview those results. Is that the main one; the costs are going down?

Is there anything else that you can share with us?

A (Witness Grubb) So that's the only resource that needs projects constructed. And so those prices

will be lower than what we initially filed. But none of the other resources were identified to need projects.

Q Okay. I believe yesterday in response to one of Mr. Thomas's questions about grid enhancing technologies, you acknowledge that the reconductoring is one of the options that is being explored in that transmission traffic?

A (Witness Grubb) In that screen, that's right. It was operating guidelines, redispatch and reconductoring and rebuilding.

Q How much faster is reconductoring existing transmission lines than, you know, permitting and developing a new one?

A (Witness Grubb) I can't -- I don't work directly in transmission. I cannot speak to that, but I would think it would be a lot quicker than having to get a new easement and building an entire new line.

Q I'm getting on toward the end.

Commissioner Pridemore asked you yesterday about uncertainty in your load forecasts and then it came out again today, as well. So this one question that I wanted to ask may help to kind of bottom that out.

With regard to your probabilistic modeling where you say actual demand could be higher or lower than projected, is there an equal likelihood that the load

will be lower as it is that it could be higher?

A (Witness Valle) Sorry. Can you clarify the question for me?

Q Yeah. So when you say actual demand could be higher or lower than projected, is that likelihood equal that it could be higher or lower?

A (Witness Valle) From the levels that we have used now, there's a likelihood that it's going to be at that level or lower.

Q Because of the choice of the P95?

A (Witness Valle) Because of the level -- yeah. Part of it. You know, it's a -- it's also the level of load that we have identified to serve the needs of the request that we have in front of this Commission.

Q Okay. Maybe that did or did not contribute to the uncertainty of the question and conversation yesterday.

Let's see. On page 27, lines 20 to 22, you say that the PPAs with Mississippi Power and with Santa Rosa Energy Center will, quote: Provide immediate additional capacity and energy to meet the growing demand.

This kind of gets back to where we started about both to capacity and energy outputs. But did Georgia Power ratepayers actually need the energy, the megawatts hours on a routine basis from these entities,

or is it just the peak capacity that's driving the need?

A (Witness Grubb) Well, anytime you add a resource, you get both. So we plan for the need for capacity, but obviously that has energy along with it.

So we talked yesterday, we need -- we need all five years because we didn't take all five years. Or customers need all five years because if we didn't, those were not going to be available for the third and fourth period when we need them. But those resources being in the system helped reliability by being there.

Q Okay. Is the average greenhouse gas emission intensity, CO2 per megawatt hour, of Mississippi Power higher or lower than that of Georgia Power.?

A (Witness Grubb) Some of the similar questions from before. I believe their fleet may be a higher emissions rate than ours, but I don't know that for certain.

But with Vogtle and the solar we've added, I would guess Georgia's is lower. But, again, that PPA is through '28 and it's from their system.

Q And so if that's the case, if their average is a higher emissions intensity, then will it make the Georgia Power customers' consumption of power slightly dirtier?

A (Witness Grubb) For those few years. But what

it's doing is it's serving load for those customers and providing reliability for those customers.

Q What about from a resource diversity standpoint?

Compared to the 2022 IRP, with the resources you're proposing in this IRP update, will Georgia Power's resource portfolio become more diverse or less diverse?

A (Witness Grubb) With this plan?

Q Yes.

A (Witness Grubb) More diverse. We're adding storage. A lot more storage that we're adding with this and the 2022 IRP. So we've only got one -- we've got one storage facility that's about to come online, but we've got hundreds that were approved in the 2022 IRP and then the thousand that we're asking for here. And we expect the All-Source IRP will have a robust response on storage, as well. So we're -- it will help diversity.

A (Witness Evans) And as the customer programs are approved and grow, that will add to the diversity of our resource mix.

Q All right. How about fuel diversity?

A (Witness Grubb) So you're adding the storage. That's solar. So that will help from that standpoint, so...

Q Is the storage exclusively charged by solar or

can it be grid charged?

A (Witness Grubb) It could be grid charged, if we needed that. There are some periods of time we expect it will be grid charged.

Q What percentage of Georgia Power's current energy mix is fossil gas?

A (Witness Grubb) I have that. We actually had it in the filing.

So it is 45 percent of capacity. I'm not sure energy -- it's slightly higher in 2022. I don't have --

Q Would you accept 48?

A (Witness Grubb) Yeah. On energy?

Q Yes.

A (Witness Grubb) Yes, 48.

Q That was from your 2023 Facts and Figures by the Numbers published online?

A (Witness Grubb) No. That's correct. I think that's what I have here, too.

Q All right. So if the Commission approves the resources proposed in this 2023 IRP Update, what will that percentage be for the winter of 2027-2028?

A (Witness Grubb) I don't have those numbers. I don't think I've run. Not that aspect of it. I don't have them here.

Q Will it increase or decrease Georgia Power's

reliance on gas?

A (Witness Grubb) This filing?

Q Yes.

A (Witness Grubb) So it depends on how much we can dispatch the CTs. And as Mr. Bush has said, if we do, it would be a more economic gas usage than what the system is now. So we don't have those numbers, but it won't drastically increase.

Q All right. Well, this kind of gets back to the conversation that was started earlier. Many, many times in the last two days we heard that this plan will put downward pressure on rates. But I think we got beyond that earlier today and we started talking about other bill impacts. Because people -- you know, customers ultimately pay a bill, not just a rate.

Is it true that over a quarter of residential customer bill is the fuel rider?

A (Witness Grubb) I haven't -- subject to check. I don't remember what the latest fuel rates are.

Q And another roughly 8 percent on the EECR?

A (Witness Grubb) Subject to check.

Q Thank you.

Have you analyzed the bill impacts from this request for -- especially for residential customers?

A (Witness Grubb) Not to bills because that

requires what's going to change in the rate case and how that gets handled through tariffs. But because you have those -- if you have other increases, what we're -- what we're seeing here in this filing, adding these loads is -- gives more load to spread those costs across and lower the rate for customers.

I can't talk per rate because it depends on how that gets allocated in the next rate case. But there is downward pressure on rates for all customers from this filing.

Q And when you say rates, though, the fuel cost rider and the ECCR are not included in your definition of rates; correct?

A (Witness Grubb) Not fuel. But the ECCR would have -- would be spread across more customers.

Q Okay, okay. What can the company do to prevent another massive fuel cost adjustment like we just had last year?

A (Witness Grubb) So that's a --

COMMISSONER McDONALD: Change administrations in Washington.

COMMISSIONER PRIDEMORE: Speak into the mike, please.

COMMISSONER McDONALD: Change administrations in Washington.

MR. JACOB: The company can do that?

COMMISSONER McDONALD: Well, that would do it.

MR. GRUBB: No, we cannot. No. The -- so repeat your question again. I'm sorry.

BY MR. JACOB:

Q What can the company do to prevent another massive fuel cost adjustment like we had just last year?

A (Witness Grubb) So, I mean, that's obviously driven by natural gas markets. And so the more we diversify the fleet, which we're doing here with battery energy storage, and a more efficiency peak can help lower those costs, all else equal.

Q All right. I think I'm on my last lap here.

You touched on this with Mr. Thomas yesterday, as well. He asked why you started the PPAs in 2024 when we don't really need that capacity until late 2025.

Why did you sign the PPAs with Mississippi Power and Santa Rosa before asking this Commission for permission to do it?

A (Witness Grubb) So, one thing, when I say we didn't need them, what I meant was we -- the target reserve margin, we had met it. They helped with reliability.

But the reason we had to move forward with those contracts before we came to the Commission, and

also sign all five years, is had we not done that and we didn't approach them until a few months from now, they would not be able to serve customers. And we would not be able to support the same level of load growth.

COMMISSIONER PRIDEMORE: Because they would have sold it to somebody else or because they would have decommissioned them?

MR. GRUBB: So at Mississippi, it would have been both. And Santa Rosa, it would have been sold to somebody else.

COMMISSIONER PRIDEMORE: Okay.

BY MR. JACOB:

Q You actually say that you've already sold 500 megawatts of the excess capacity to, quote, a regional electrical service provider from now through September 2025.

A (Witness Grubb) That's correct.

Q So how does that jive with your prior assertion that PPAs will provide immediate additional capacity for Georgia Power customers if you've already sold that capacity for the next two years?

A (Witness Grubb) Well, you still have the 200 megawatts. But the main thing about the immediate need was that winter of 2025.

We can't construct anything by the end of 2025.

That's less than two years from now. And so it's that first year of need that those PPAs help us meet.

Q Who is the regional electrical service provider that you sold it to?

A (Witness Grubb) Trade secret. It's been filed in the DR as trade secret.

Q Why didn't you just let Mississippi Power sell the power to them through September of 2025 and then have our PPA for supply to Georgia Power starting October of '25, rather than being a middleman for the next few years?

A (Witness Grubb) The first action was to procure and get those resources for Georgia Power and then turn around and make sure that other entity still needed them. So it was -- if we had done the other, the other entity was interested in five years, too. So they would have had all five years.

So we had to -- we needed it for our customers for five years and then we sold the shorter years to them.

MR. JACOB: All right. That's it. No further questions from me.

CHAIRMAN SHAW: All right. Thank you, Mr. Jacob.

We'll break for lunch and see everybody back in

here at 1:20.

(A recess was held from 12:24 p.m. until 1:20 p.m.)

CHAIRMAN SHAW: All right. We will go ahead and get started. We have got just a few more intervenors, and we will start where we left off. I will call up Southern Renewable Energy Association.

Good afternoon, Simon.

MR. MAHAN: Good afternoon, Commission.

CROSS-EXAMINATION

BY MR. MAHAN:

Q Good afternoon, gentlemen.

A (Witness Evans) Good afternoon.

A (Witness Valle) Good afternoon.

A (Witness Grubb) Good afternoon.

A (Witness Bush) Good afternoon.

Q I was hoping a lot of folks would ask questions that I was going to ask, but, unfortunately, they didn't. So please be patient with me as we kind of walk through a number --

CHAIRMAN SHAW: I would have thought Mr. Baker covered them all.

MR. MAHAN: Yes. He told me he cut his by half, so I think he cut my half on that side.

COMMISSIONER MCDONALD: With that opening statement, is that a warning for us? Is that what

that is?

MR. MAHAN: It's a notification maybe. Not so much a warning.

BY MR. MAHAN:

Q So yesterday, there was some discussion about expediting an RFP process. Do you remember that discussion?

A (Witness Grubb) Yes.

Q And you had said that you hadn't had conversations with Commission staff regarding expediting an RFP process; is that right?

A (Witness Grubb) We had discussions with staff around the RFP for the All-Source, and so we did talk about expediting it in terms of the All-Source. I would have to go back and look in terms of the discussions we have had, but, again, you can't expedite enough to meet a three-year earlier year of need.

Q Well, what was staff's position on expediting the All-Source RFP?

A (Witness Grubb) I can't state staff's position.

Q What is your position on it?

A (Witness Grubb) On expediting an RFP to meet the needs in this case, we cannot do that. There's not enough time.

Q Sure. But beyond this is case.

A (Witness Grubb) Beyond this case for what?

Q Next year. Later this year.

A (Witness Grubb) So we are working with staff on the schedule for the All-Source RFP right now.

Q And in order to expedite it, there is a value to customers to expediting it; is there not?

A (Witness Grubb) So the value the expediting is -- the resources in that RFP are going to serve the needs years of the winter of '29, '30, and '31. And so expedite -- that doesn't change, because this IRP update addresses the ones before that.

Q Okay. So we are totally taken care of until '29?

A (Witness Grubb) From this IRP update, we're a little short in '28, and that's why we have identified there is some other resources we are looking at in terms of the DER. But the All-Source RFP that was approved in the '22 IRP will meet the needs in the winter of '28-'29, '29-'30, and '30-'31.

Q And you said a regular RFP schedule takes about two and-a-half years. Is that pretty typical, or does that seem kind of long for y'all?

A (Witness Grubb) So we have said two to two and-a-half years, is what we filed.

And so, Commissioners, when we look at RFPs,

what we do is we look at the year of need, and we need a minimum of five years, or right at five years minimum, to move towards that. So we would start with the year of need. You need at least three years to build new resources, and you have got a two-year process.

So to meet a year of need by the end of '25, we would have had to start that RFP in 2020, way before we ever had any indication of these loads. So that's why we talk about there is not enough time to do the RFP process, including the critical parts of the evaluation, and then physically build resources, especially considering transmission.

So, again, completely supportive of the RFP process. We have already done -- we have done 20 since 2006. We have got seven that we are doing coming out of the IRP, but they do not work in this case.

Q So y'all have some anticipated retirements coming up in 2028, though; right? Bowen and Scherer, I think, are the units?

A (Witness Grubb) So not Bowen. In the 2022 IRP, the Commission approved a decertification of Plant Gaston in Alabama by the end of '28 and Scherer 3 by the end of '28. We will re-address those and reevaluate those in the 2025 IRP, but our capacity plan shows those retirements.

Q Okay. And so is it possible that in the 2025 IRP we get there and you say, again, we are not going to have the ability to issue a two, two and-a-half year RFP, three years' worth of construction, we are going to have to extend those units out beyond 2028 because we just don't have enough time?

A (Witness Grubb) So the 2025 IRP will take into consideration the results of this outcome and will reflect the megawatts that are being met through the All-Source RFP, so it would be looking at needs in the winter of '31-'32 and beyond.

Q Okay. So it is not currently slated to cover the gap related to the retirements in 2028?

A (Witness Grubb) So the -- if we move forward with the retirements in 2028, those megawatts are reflected in the needs that will be met through the All-Source RFP.

Q But you just said the All-Source RFP is supposed to take care of us in '29 and '30 and beyond?

A (Witness Grubb) So those units are in -- are in -- are approved to continue through the end of '28. So the All-Source RFP takes care of the winter of '28-'29, '29-'30, and '30-'31.

Q Okay.

A (Witness Grubb) It is a three-year RFP.

Q Okay. Thank you.

So the -- you have established very well that the need is very short term and very soon. Can you -- just briefly, do you have the capacity need for the '25-'26 winter term? What is that megawatt number?

A (Witness Grubb) So it was in the filing. So it was 100 -- it was a small need. It was -- I think it was 100 and -- let's see. I have got to find it. So it was 175 megawatts, but then the next year is 1,875.

Q So that's 2027?

A (Witness Grubb) It is the winter of '26-'27, meaning you need resources to be on-line in less than three years.

Q December '26?

A (Witness Grubb) December '26, January '27, and February '27.

Q Okay. So when the data in the file says we have a 170-megawatt need in the year 2026, it's not including December of that year?

A (Witness Grubb) If you look on the needs chart on page 11, it shows the year '25. It says 2025/2026. That means you have got to have them on-line by the end of '25.

Q Okay. But the Mississippi Power and the Santa Rosa Power purchase agreements are going to cover us

through the end of 2026; is that right?

A (Witness Grubb) So they will -- they will get -- not the winter of '26-'27. They are not enough to meet that, which is why we have identified the other resources to deploy by the end of 2026. Mississippi and Santa Rosa are not 1,875 megawatts.

Q Right. Do you happen to know if Mississippi Power is planning on building or had been planning on building any new generation to make up for the 2028 retirements that they were planning?

A (Witness Grubb) I don't. I don't know. Again, the reason those units were going to be either sold or retired was because they had more than the reserve margin target. So I do not believe they would retire them and then turn around and rebuild. But -- depending on what things change at Mississippi, but the plan right now would be to retire those units.

Q Which units --

A (Witness Grubb) Or sell.

Q Which units specifically are they retiring?

A (Witness Grubb) So in the order that was from their Commission, it was going to be, I believe, Watson -- some Watson units were going to retire by the end of this last year.

Q Okay. And Plant Daniel?

A (Witness Grubb) I think it was in 2027, maybe, '28. I would have to look. I have got it somewhere.

Q No, that's okay.

A (Witness Grubb) But they had -- so the Commission recommended a retirement of 950 megawatts. It was up to Mississippi to come back with a plan to what to transition out of.

Q Okay. Let's move on a bit and talk about transmission. In the 2022 integrated resource plan, the North Georgia reliability assessment took a considerable amount of focus. How is that North Georgia reliability assessment going currently?

A (Witness Grubb) Yes. So good question. So, Commissioners, we've included some of those projects in our ten-year plan that we update the staff and the Commission on. So we have identified the projects for the coal retirements and are moving forward with engineering on those.

And then for the other strategic projects, for the South, the North renewable flows, we have identified the corridors that are -- that are -- need to be increased for their flow capability and they are working with the ITS members on that.

Q Will we receive an update on this study more formally at some point in the near future?

A (Witness Grubb) So, Commission and the staff, based on the 2022 IRP, we provide that each year, so we will be meeting with staff first part of this year to update that ten-year plan.

Q And is the ten-year plan different from the additional transmission analysis that you are providing later this month?

A (Witness Grubb) It is in terms of the -- the filing that we are providing the end of this year has the load forecast level that's in the 2023 IRP update to look at what -- what transmission projects are needed for the resources we are asking in the case. The load forecast in our transmission plans are always a year behind. So the normal ten-year plan that gets filed will have a different load forecast.

Q So the transmission analysis you have already performed for this IRP does not include the 6,600 megawatts of load growth that you are anticipating?

A (Witness Grubb) At the time we ran the screening, Commissioners, we took the confirmed loads that we had at that time. When we do our transmission plans, we model to NERC reliability standards based on firm and future firm resources and confirmed loads. And so it was a load forecast plus contracts we had won in the fall.

We are increasing that load amount with what we are going to file this month to match the load amounts that are in this IRP update. And, again, we have identified that the -- there is no change in the resources, in the transmission projects needed, but the cost on the Yates projects will be lower.

Q Why would the costs on the Yates project be lower if you are not accounting for all the load that you are projecting in the IRP?

A (Witness Grubb) So the supplemental filing that we will do this month does include a load level similar to what is in the 2023 IRP for that screening. And the reason for that cost decrease would be filed later this month.

Q Is it possible that you are pushing off transmission costs on those other customers in order to alleviate congestion on the grid that would otherwise be required by installing Plant Yates upgrades?

A (Witness Grubb) Would you go through that one more time?

Q Yes, sure. Why is it cheaper now that there is more load in the model when Yates already identified a transmission need? Are those new customers effectively paying for that new transmission upgrade?

A (Witness Grubb). No. I don't want to get too

far ahead of the filing, but it is an update in the project cost.

Q And that --

A (Witness Grubb) And that will be explained later this month.

But it was not -- it was not moved to any other thing. It was the identification of the projects to get delivery from Yates, and there was a change in one of the -- some of the projects associated with Yates. But nothing else has changed in the case.

Q So in the base case of the screening analysis, did you include the 3,350 megawatts of new generation that's going to be added from the CARES RFP that's about to start accepting bids tomorrow?

A (Witness Grubb) I don't believe we did because we don't know where those resources would -- where they would be. So it was based on the generation, and it was more than just what we looked at here. As we filed, there were a few other resources we looked at, as well, that we were considering for deployment.

So, no, the -- I don't believe that's in there because we don't know what those bids are. So that process takes place through the RFP process when those bids come in. Transmission evaluations take place then.

Q And y'all accredit solar-plus batteries as a

winter capacity resource; right?

A (Witness Grubb) Well, it is both. It is not just winter. That's what we focused on in this case, but there could be conditions where it is helping in the summer, as well.

Q Sure. So the CARES program, the CARES RFP that's about to go live tomorrow accepting bids, solar-plus battery projects are allowed to bid into that RFP; correct?

A (Witness Grubb) That is my understanding. I am not familiar with all of the use cases and the details in that RFP, but they would allow storage to accommodate that, those solar resources.

Q And if solar and storage projects are ultimately selected out of that process, they would give additional capacity to the system?

A (Witness Grubb) Yes. The -- depending on the use cases in that RFP, and we have done that some in the prior ones. But those units will not be on-line until the late '20s. And we don't know what type of bids are going to win that solicitation.

Q Is the RFP not requesting start dates as early as 2026?

A (Witness Grubb) I don't know. I haven't looked at that RFP. It could be, but, again, it is

focused on the latter half of the '20s. But we don't know what is going to win in those resources. We don't know what capacity equivalents it will be. So that's why we have identified these resources we have to move forward with.

Q But in the modeling, you assume that a hybrid resource, a solar-plus battery resource, is 100 percent accredited in the wintertime?

A (Witness Grubb) Which model?

Q Your capacity expansion model.

A (Witness Grubb) Yes. Based on a storage use case that's four hours minimum that's used for capacity reasons.

Q Okay. When we are talking about the Mississippi Power power purchase agreement, are those -- is that -- are those -- is that PPA included in your transmission screening analysis?

A (Witness Grubb) It is in the fact that the resources are in there. The PPA doesn't change the physical nature of the Southern System that we studied.

Q So you didn't actually physically model moving power from Mississippi over to Georgia?

A (Witness Grubb) No. But we had those units available through those years in the transmission screening analysis.

Q Okay. And similar in the transmission screening analysis, you evaluated the Plant Lindsay, the Lindsay Hill facility over in Alabama; correct?

A (Witness Grubb) Yes. We began with -- we had to do it in tiers, and so we did the system units first. And then we moved to market resources, and then we moved to the others.

And, again, Commissioners, we were doing this in parallel with identifying resources that were not under contract and that we could contract with or that we could deploy. So while we were looking from a generation planning standpoint at whatever our resource options are, we were also doing transmission screening to make sure that we didn't go commit to a resource that we couldn't have transmission for to provide in the years of need that we have it.

Q Now, Lindsay Hill, it has been around for quite some time. Can you describe the facility a little bit more?

A (Witness Grubb) I think it is a combined cycle that's in Alabama. I don't know the age of it, but it has been around.

Q It has been in the portfolio.

A (Witness Grubb) But I don't know if it has been contracted with or those types of things.

Q Okay.

A Or what transmission service it's had.

Q But y'all had found a transmission constraint associated with Lindsay Hill which knocked it out of the running?

A (Witness Grubb) That's correct. There were projects that had to be done to allow the delivery of Lindsay Hill that was outside the time frame of this IRP update.

Q Okay. So even though Lindsay Hill has been around for a while in the Southern pool, there are transmission constraints that limit its ability to provide power to Georgia?

A (Witness Grubb) So I am not a transmission planner, Commissioner, but what the -- what we are looking at in transmission planning is firm and future firm resources. And so just because a resource is physically available does not mean that it necessarily has transmission service.

And so when those -- for example, we may have a purchase power agreement with a resource that's a designated native load resource for Georgia Power. When that contract expires, we do not show that as a firm resource on the transmission system, because it is not serving for loads.

So I can't speak to the different status of Lindsay Hill, but when we evaluated it, it showed that you had to have transmission projects. And it is a very dynamic system. We have things changing every day.

A (Witness Bush) I would just like to clarify, Commission, Lindsay Hill is not in the Southern pool. So when you think about the Southern Company pool, it is the retail operating companies and the companies owned by Southern Company and PPAs that might be in there. So Lindsay Hill, we do not consider it a part of the pool.

Q Is Santa Rosa in the Southern pool?

A (Witness Grubb) No. It is in the Florida Panhandle.

Q Did the transmission analysis, the screening analysis, include the Santa Rosa PPA?

A (Witness Grubb) Yes, it did. We studied it again. If you look at the filing on page 1 and the transmission screening, it steps through the order in which we evaluated it. So it was evaluated.

Q Okay. But Lindsay Hill was included in each different scenario that was evaluated, as you described it. It was kind of tiered as you were adding different resources; is that right?

A (Witness Grubb) That's correct. And the filing that we will make this month does not include

Lindsay Hill, because we did not move forward with it. And again, we have seen no changes to the identification of the projects needed to accommodate Yates or any of the other resources.

Q Great.

So the company participates in the SERTP process. Are you all familiar with the Southeastern Regional Transmission Planning Process?

A (Witness Grubb) Somewhat familiar with it. I am not involved in it and don't attend the meetings or anything. But I know it is in -- it is a process that our transmission planning groups are engaged in.

Q And through that process, the company provides its ten-year plan to its neighboring utilities like MEAG and ITS and TVA and Duke and the other utilities; is that right?

A (Witness Grubb) That's right. But, Commissioners, the ten-year plan is an ITS plan. So we don't provide it to the other ITS members. We develop that plan in conjunction with them.

Q And if a project is contained within the ten-year plan and it benefits the overall system, for the ultimate responsibility to pay for it, to pay for those projects, relies on the entire system, not the individual generator; right? Or not the individual customer?

A (Witness Grubb) Yes, not the individual customer. I think for serving load, those transmission projects, if it is benefiting all customers, is paid for by all customers.

I would say, Commissioners, though, while we are talking through this -- and Mr. Evans can help here -- when we look at each Customer Choice job, we look at their local transmission and distribution cost and allocate those costs to the job. And we do assign a cost of the bulk power transmission system to those Customer Choice offers, as well.

A (Witness Evans) Yes, that's correct. Those investments that are there to serve just that customer are borne by that customer. And they are a portion of the upstream cost. So those infrastructure costs that are shared by many customers or all customers, their portion of those upgrades are borne by them, as well.

Q So if there was a generator, for instance, that wanted to move forward or accelerate a transmission project in the ten-year site plan, could they do that? Is that allowed?

A (Witness Grubb) When you say a generator wants to move forward a project?

Q Yes. So if there is a project identified in the ten-year plan that, you know, says it shows up in

year five, but a generator wants to come in and expedite that project to year two or three, is that a possibility?

A (Witness Grubb) As -- I don't know the driver of the generator wanting to do that, but I think when we -- yes, but when we study generators, if it changes the timing of those projects, whether it delays them or advances them, that gets captured in the screening analysis, or any of our transmission analysis.

Q Right. So that would potentially allow generators to get ten-year transmission projects built sooner rather than later; right?

A (Witness Grubb) Yes. It depends on the process in which that resource is going through, whether it is going through an RFP, we would identify them there. If they are a qualifying facility, we identify them there as well. So it just depends on the nature, the vehicle in which that resource is being evaluated.

Q So is that option available under the -- both the large generator interconnection process and the qualifying facility interconnection process?

A (Witness Grubb) I believe so. I am not a transmission planner, and I don't do interconnection studies and don't deal with interconnection agreements a whole lot. So I will just say that our transmission planners are capturing those aspects when we evaluate

those.

Q Now, still on the transmission analysis, the screening analysis, the IRP is requesting adding 1,000 megawatts of battery storage, the 200 megawatts associated with the 200-megawatt solar facility, 128 megawatts at Robins, and 49.5 megawatts at the Moody Air Force Base. Did you run the transmission analysis associated with the screening analysis associated with those known battery projects?

A (Witness Grubb) We did not because, again, those resources are being placed at those facilities because they don't require transmission projects to allow for delivery from those resources.

Q And I think, as everyone recalls, I am not from here. So are the solar projects and the Air Force base projects, are those in North Georgia or are they in South Georgia?

A So Robins is in Warner Robins, which is just south of Macon, so Central Georgia, and then Moody is Southeast Georgia.

COMMISSIONER MCDONALD: Valdosta.

A (Witness Grubb) Valdosta. Okay, sorry. I was thinking -- so, yes, Valdosta. So they are not.

BY MR. MAHAN:

Q Did you run a transmission study for the

remaining, I think it is 622 megawatts of battery storage that you are requesting?

A (Witness Grubb) We did not, because, again, we are going to identify sites very similar to Robins and Moody's that don't require transmission projects to be built to facilitate delivery of those resources.

Q Are those projects currently in the generator interconnection queue?

A (Witness Grubb) I am not sure. Not yet, because we haven't identified the sites.

Q Are you familiar with a FERC Order 2023?

A (Witness Grubb) Somewhat familiar. I know it is a recent one, and our transmission policy groups and planning groups are evaluating that, but somewhat familiar with it.

Q Could you describe it just a little bit?

A (Witness Grubb) Just a little. One of the things that that order's doing is instead of -- it is trying to look at the queue order and how things are done in the queue. And there is a -- I think there is a requirement for a certain time of year to be in the queue to be evaluated, as opposed to the current process, which is, I think, more first in, first out type of thing.

I will say, though, Commissioners, in our queue and what we are evaluating in the Southeast, we have

very -- very few projects in the queue that don't get studied. Our time to study queues are quite quick. But, yeah. So we are still thinking through how that impacts our timing, so I am somewhat familiar with it.

Q So the 622 megawatts of company-owned battery storage hasn't been studied in the transmission analysis, isn't in the generation interconnection queue. There is a new queue process that's starting up come April. I think that's right?

A (Witness Grubb) I believe that's -- somewhere in there.

Q So it is a brand-new process. What is the likelihood that the company actually gets generation interconnection studies from the 622 megawatts that haven't been identified and aren't currently within the queue, get those projects out of the queue, constructed, operating by 2026?

A (Witness Grubb) So, Commissioners, I am not -- I don't know the details on how we are going to handle the transition from the prior process to the new one to speak to what that order will be for resources.

Q Wouldn't it be easier just to procure existing resources that are already in the generation interconnection queue that maybe have their studies already done?

A (Witness Grubb) Are you talking about storage projects?

Q Sure, or hybrid projects.

A (Witness Grubb) About -- potentially, but what we have identified is that the -- the company identifying solar sites that we can put the storage at, and not all of them are our sites.

Q So if it is not your site, have you already identified these sites, or will you identify these sites?

A (Witness Grubb) We are -- and Mr. Bush can help me. We are looking at a portfolio of sites, and we are narrowing in on what those specific sites will be.

A (Witness Bush) That's correct. We are actually engaging many of the PPA providers for Georgia Power Company that have large solar sites, engaging them to find their interest in allowing us to put a battery there at that site, in conjunction with the interconnection and delivery service that already exists at that site.

Q With the amount of load growth that the company is projecting, are you working with ITS participants to deal with this amount of load growth? How are you interacting with other ITS participants around it?

A (Witness Grubb) So there is nothing different about that process, Commissioners. What we will do is as

we update load forecast, just like all the other ITS members, it will move into the transmission planning process. Again, it's a year later, because you have got to run the loads through your generation process, then turn it over to transmission. But that's always been the case. So it will flow through the ITS discussions just like it always has.

Q Let's move on and talk about the capacity expansion models and plans. Specifically, I am talking about the supplemental errata that y'all filed on December 7th.

A (Witness Grubb) On the resource mix study?

Q Yes, sir.

A (Witness Grubb) Yes.

Q So help me understand here. The way the model works, is that it optimizes -- and I am going to just describe it and let me know if I am off base here. The model optimizes the full Southern Company system first, and from that, you get a system capacity expansion output.

A Yes. It is the Southern System, specifically, the retail operating companies, the three retail operating companies. It is meeting the system need.

Q How does the model separate the capacity needs based on state jurisdictions?

A (Witness Grubb) So what -- the model solves the system, and then what it does, it is pretty simply -- it is just, after we have solved that model, it allocates to the operating companies in two steps. The first step is it adds generation to the operating company that has the lowest amount of reserves for planning than the others.

Because if you have a need, one of the operating companies is not at their own specific need. And it will add to -- for lack of a better term -- the shorter company, move it to where it is matching the next shortage, and it will add that capacity until they are equal. It will do that, and then what it will do is if there is a different type -- in other words, if it builds a combined cycle, and in storage, it will take energy balance into account as well. So it will -- if there is an operating company that needs resources and needs energy, it will give them the more energy intensive part of the resource.

Q And so does -- this is the Aurora planning software program; correct?

A (Witness Grubb) That runs the system solution, that's correct.

Q Does that model include transmission constraints?

A (Witness Grubb) It does not. Again, Commissioners, what that generation planning model is doing is identifying the resources that are the most advantageous from a generation standpoint, knowing that, over time, we will build the transmission system to allow delivery from those resources.

Some of our earlier production cost models do put in some things if we have must-run conditions and those types of things. But again, Aurora does not, but that's what our transmission planning process does is evaluates the resources.

Q Thank you for that.

And then in the Aurora model, did the company limit the amount of battery storage that could be added in any particular year?

A (Witness Grubb) I know we do -- I would have to look, Mr. Mahan. I do know we limit some. I know we limit -- I just can't remember. I would have to look.

Q That's okay. Just yes or no.

A So it -- yeah, I can't remember if we do. I know we do on -- on some of the resource types. Subject to check, we may do the same on batteries. I would have to check.

Q Well, so the question was about batteries. I had a similar question about solar and wind, but I will

let you off the hook.

A (Witness Grubb) I believe we filed them in the DR. I just can't remember which DR since there has been 270 of them filed.

Q But there weren't any hybrid projects that were modeled as a resource in the capacity expansion model; right?

A (Witness Grubb) No. When you say "hybrid," I'm assuming you mean solar-plus storage?

Q Solar-plus storage, yes.

A (Witness Grubb) No. What Aurora -- what the expansion plan model is doing is it is looking at solar from an energy production standpoint, and it is looking at storage from a capacity standpoint. So it is not -- it is not dependent on location, if they are located together or not. It is looking simply at solar providing energy value and storage providing capacity model. Whether you model them as a hybrid or not, it wouldn't really change the outcome at all.

Q Well, so does solar not get a -- some sort of an accredited value for Aurora, or is it set at zero?

A (Witness Grubb) Not generic solar.

Q It is set at zero in the model?

A (Witness Grubb) It is set at zero. So if we -- once we know solar resources through an RFP, they

would get it, but a generic solar does not.

Q And so --

A (Witness Grubb) Because again, it is being added for energy value.

Q So the company performed an effective load carrying capacity analysis for solar, though; right?

A (Witness Grubb) To use on projects that we have project profiles for in evaluating RFPs, that's correct.

Q But you didn't include that evaluation in the model for capacity expansion?

A (Witness Grubb) That is my recollection because, again, it is looking at adding it for energy resources. And it does allow it to be added before we have a capacity need, so it does do that.

Q All the batteries that are added in the model -- well, all the resources in the model are modeled as company-owned resources; is that correct?

A (Witness Grubb) So as we have always done, Commissioners, not knowing the results of RFPs, we have always shown the avoided cost or the cost of a capacity is the company's cost to build, which is a standard utility practice.

So when you are talking about a generic expansion plan, you model that cost to build, because

that's what you would deploy unless the market, through an RFP, bid it at a lower cost. So that's what we have always done.

Q And so the model uses company ownership as kind of financial fundamentals, and the model supports the company ownership in this docket?

A (Witness Grubb) No, I wouldn't say that, Commissioners. It is not based on ownership at all. It is just a cost. The production cost model or the Aurora model just has a cost to build a CT, a cost to build storage. In the past, we have used PPA cost for solar.

So it is not an ownership aspect at all. It is simply the cost of those generation types based on the work that Mr. Bush and team do across the company, looking at what the cost to build those technologies are, based on our latest information. So it is indifferent between ownership.

Q This is kind of a technical question. With the outputs that were provided from the capacity expansion model -- again, in the supplemental errata -- you have got different tranches of battery storage, T1 T2, T3, T4. I didn't see anything in the materials -- or maybe I missed it -- what those different tranches meant and why y'all modeled it like that. Could you explain that, please?

A (Witness Grubb) Yes. So it is something we have addressed in some prior IRPs as well. So as you deploy batteries on the system -- and Mr. Bush can help me here if he has anything to add. When you add batteries, they are energy limited. So you have a four-hour battery, a two-hour battery, an eight-hour battery.

If you think about our reserve margin study where we are studying 700,000 cases and all the different reliability events, they are -- a four-hour battery will allow you to respond to certain reliability events. But as you add batteries, it kind of depletes that system.

So once you have deployed a certain number of four-hour batteries, you need an eight-hour battery to give you an additional reliability impact. So those tranches are just changes in the capacity equivalents of those batteries, as you add more onto the system.

Q So there is a declining capacity value for resources that are just added at a later date?

A (Witness Grubb) For batteries, yes, because --

Q Yeah.

A (Witness Grubb) Yeah. Not CTs or anything else. But that's just the uniqueness of batteries.

Q And solar is already at zero?

A (Witness Grubb) From a capacity equivalent

standpoint. It would still capture -- the more solar you add, the more that -- the harder it is for solar to continue to give you energy savings. But, yes. It is not a capacity equivalents issue.

Q The batteries that are being added, do you happen to know if they are going to be evaluated under a network resource interconnection service, or an NRIS, versus an energy resource interconnection service, or an ERIS?

A (Witness Grubb) Are you talking about the batteries that we are proposing in this case?

Q Yes.

A (Witness Grubb) I don't know. Again, that's where I don't deal with transmission planning and interconnection agreements, but we have put native load reservations out there. Whatever, it will go through that process. I just don't know the difference between those two that you are mentioning.

Q So you don't know the difference between NRIS versus ERIS?

A (Witness Grubb) I don't. I would think the -- you said the NR is native load resource?

Q Network.

A (Witness Grubb) Network? I mean, I would assume it would be network. I don't know what the energy

is, but again, we would have to get back with you on that. I believe there is a DR on that. We just haven't submitted it yet.

But the point, Commissioners, is we will go through the process needed to make sure that those batteries are designated as native load resources to serve our customers.

Q Would you agree that batteries provide multiple system benefits, multiple values?

A (Witness Grubb) Yes. As we have said in this proceeding, yes.

Q How are those multiple values accounted for in either the economic analysis or the capacity expansion model?

A (Witness Grubb) So for the capacity expansion model, I think it looks at all the different cases. It looks at, is there energy arbitrage opportunities; right, charging at a lower price than you discharge it? Kind of like we do with hydro, pump storage hydro, and then it also looks at dispatch to meet the peak.

On the economic analysis, it is the same model that's looking at energy. So I think it's -- it depends on what the system needs at that time. I can't speak in any more deal than that, Mr. Mahan. Not to dodge it; I just don't recall. But it is going to look at the

different use cases that a battery can handle.

Mike, you have anything to add, or is that --

A (Witness Bush) Yeah. What I recall from the economic analysis was we used energy arbitrage and then the capacity value for the battery.

Q Okay. Moving on to the Plant Yates facilities. How are the natural gas fuel supplies handled in the model?

A (Witness Grubb) I am sorry?

Q How are the fuel supplies for the Plant Yates units handled in the capacity expansion model? Is the model assuming a firm transmission or transport of natural gas fuel to those facilities?

A (Witness Grubb) So in the resource mix, or the expansion plan model, we did not model Yates 8 through 10. We did that in the economic analysis. But it would be based on what we are proposing, which is availability to gas, but oil in peak times.

Q Say that last part again. I am sorry. So are you pre -- are you anticipating or planning on the Yates units having firm natural gas contracts?

A (Witness Grubb) No. And we have addressed that in the filing and in this case. We did not move forward with procuring firm transportation at this point because of the timing and then needing to deploy those.

And we have typically done CTs on natural gas and oil, so we do not have firm transportation. But we expect to have access to gas in many hours of the year, and we have talked about being able to use the gas that's at Yates 6 and 7. If Yates 6 and 7 aren't running, we can use it on the CTs.

Q So the company is going to procure natural gas fuel from a third party?

A (Witness Grubb) From a commodities standpoint, yes. We would -- if we have gas and we could -- and we need to run those units and it is available, we would run it.

Q So that sort of contract, that fuel contract, is like a power purchase agreement but for fuel?

A (Witness Grubb) Yes. I mean, I -- I think our fuel services group out of Birmingham, they have contracts with suppliers, and so they can purchase it from it daily. I'm a little rusty on my gas contract structure, but I don't think you have to enter it in for each day at the resource. There is some master agreements that they do that procure gas under, is my understanding.

Q And do those companies that serve gas for the whole system, do they have an obligation to serve Southern Company customers first?

A (Witness Grubb) In terms of?

Q Providing gas. If there is some sort of constraint or conflict between Southern Company power plants versus residential load or commercial load for the natural gas fuel, are you all first in line, or are there other customers that are first in line?

A (Witness Grubb) So Mr. Bush can add on here if he needs to, but, Commissioners, when we purchase FT, then that's what we are doing is we're reserving our space on the pipeline to make sure that we get that gas as it's available. So it is a portion of the pipeline.

If we get gas like we are talking about on a daily basis for Yates, we are buying that pipeline capacity from someone else. So it is -- they -- the pipeline suppliers are providing it for the people who share the FT on that pipeline.

Q And we have heard a fair amount about the dual fuel capability of these Plant Yates facilities. How much -- it is oil that's -- or a petroleum-based product that's going to be the secondary fuel source; is that correct?

A (Witness Grubb) Yes. It's ultra-low sulfur diesel.

Q All right. About how much of that quantity is going to be available on-site? And what I am trying to

get at is how long duration can you run off of that -- that diesel fuel at those particular sites?

A (Witness Bush) We will have storage on-site to run 72 consecutive hours at maximum output of the resources.

Q Give you a moment to get your drink.

A (Witness Grubb) No, it is good. It is good.

Q Are y'all familiar with the company's avoided cost projections?

A (Witness Grubb) Yes.

Q And the company filed an updated avoided cost informational supplement in October; is that correct?

A (Witness Grubb) Yes, the 13th.

Q And are avoided costs going up or down over the next five to ten years?

A (Witness Grubb) So that will depend. We would be doing those updated projections. I don't know that there was a lot of difference. What we filed is our 2023 version, so we would be updating that this year. I don't know that our gas forecasts change that much from one year to the next, so it is just going to depend. I wouldn't expect a drastic change, though.

Q Did the company project a fuel cost decline in the 2022 IRP? For natural gas, in particular?

A (Witness Grubb) We did, because if you

remember, I think the initial times when we were in the IRP were pretty high. We used NYMEX for the first two or three years, and I believe they were higher and then dropped back down, if I remember.

Q But the company recently received approvals for increasing the natural gas fuel costs on customers; is that correct?

A (Witness Grubb) Yes. But that's based on actual gas usage and then a short-term projection of gas usage in the fuel case.

Q Going back to the full avoided cost update from October, do you recall that it shows a zero-dollar-per-kW value payment for capacity through the year 2029?

A (Witness Grubb) Yes, it does. Because that was based on 2023 data, which that was when the need year was. That's correct.

Q The need year through 2028 into '29?

A (Witness Grubb) So the winter of '29 was our capacity needs year coming out of the '22 IRP, that did not change until after this filing. So we would update that whenever we file it this year.

Q But the avoided cost filing was filed on October 13th?

A (Witness Grubb) That's right. Using 2023 data. It was updated. It was updated. I can't remember

the other -- but, yes, so again, at that point, we were mainly updating it.

Commissioners, the important thing around the avoided cost projection is that capacity price is not paid to any of the contracts from a QF standpoint. That's just an indication of what it may be.

Q Sure. And that avoided cost capacity payment forecast is part of what other independent power producers might evaluate to set up shop in the Southern pool; correct?

A (Witness Grubb) I can't speak to what developers base their decisions on, but it could be one of the things they factor in.

Q So if you were an independent power producer and you saw zero dollars between now and 2029, would that incentivize you to build here?

A (Witness Grubb) I am not a developer. And again, from this standpoint, from a -- from a developer's standpoint, they have seen our update filings, and they know the IRP. So when we have updated that need year, they now know it is updated. This isn't the only indication of what our capacity need year is.

Q All right. Going back to the fuel cost real quick. How does the company ensure that the fuel costs in the model are not -- are reflective of the actuals as

opposed to deflating the natural gas costs in the model to incentivize building natural gas resources in the model?

A (Witness Evans) Which model are you referring to?

Q Aurora.

A (Witness Grubb) Could you go through that again? There were three or four steps there. I want to make sure I am following you.

Q Sorry. Yeah.

A (Witness Grubb) That's not a criticism. I just want to make sure I'm clear on your question.

Q No, no, no. I tried to shorthand it, and I shouldn't have done that.

A (Witness Grubb) Sorry.

Q Let me just read it. How does Georgia Power ensure that fuel costs are not deflated or neglected when forecasting resource costs for selection in its resource portfolio?

A (Witness Grubb) So in the expansion plan model, we use our fuel forecast that we do annually that we -- every three years we bring to the Commission. And so that fuel forecast is used in the system planning models, and we look at multiple scenarios. And so we have a commodity forecast for existing customer --

company resources.

In PPAs, we will use the true differential between that price and the basis. And then for generics, we will use a system -- system-weighted type basis differential or delivery cost. So it is a -- it is based on the long-term forecast from the Energy Information Administration.

Q Let's move on from natural gas, and let's talk about wind energy for a moment. How is the capacity value of wind energy incorporated in the Aurora model?

A (Witness Grubb) I -- subject to check, I would have to check on that, but I believe it would be an ELCC if we were giving it that capacity value. I just can't remember if we are showing capacity value to it or not.

Q Because wind is typically more of a winter-peaking resource; is that correct?

A (Witness Grubb) Right.

Q Did you also include the Production Tax Credit for wind energy?

A (Witness Grubb) I know we did the IRA on solar. So subject to check, my belief is we have done the same thing on the wind energy, as well.

Q Great. Was the Southeastern Energy Exchange Market modeled?

A (Witness Grubb) No. You are speaking to the

SEEM process?

Q Yes, sir.

A (Witness Grubb) No. And, Commissioners, we talked about this in the last 2022 IRP. SEEM is not for capacity planning purposes. It is not for firm resources. It is a 15-minute energy exchange between the participating customers, and so there -- it is not an impact on planning. So it is not modeled in any of our expansion plans or any of our economic analysis.

Q Great. Let's move on and talk just briefly about the capacity RFI.

A (Witness Grubb) Okay.

Q The request for information; not the RFP. The results were shared in the filings, so thank you for sharing those. Are you going to use those capacity RFI -- that capacity RFI information that you solicited from the market to help inform the company's bids for the All-Source RFP?

A (Witness Grubb) Are we going to use the RFI to impact the company's bids or just --

Q Yes.

A (Witness Grubb) -- bids overall?

Q Yours.

A (Witness Grubb) No. We -- Commissioners, when we bid resources into RFPs, as the company, we do it at

our cost to develop those projects.

Q And so that's --

A (Witness Grubb) Just the same way Mr. Bush is developing the projects in this filing, we don't bid in a price. We submit our cost.

Q And so all of your competitors provided you this information, but you are not going to use any of that information for your own sake?

A (Witness Grubb) So first, the pricing, very few of the participants provided pricing, and it is not -- it is subject to change. But, no, we will base our company-owned proposals on our cost to develop.

Q Let's talk a little bit about the military bases. So are you familiar the Department of Defense has carbon goals?

A (Witness Grubb) Yes.

Q To reach 100 percent carbon-free pollution by 2030?

A (Witness Grubb) That is correct.

Q With the 13 military bases in the Georgia system, how is this IRP going to help support that requirement in the next five years?

A (Witness Grubb) Yes. So as we have talked about before, battery energy storage systems help with the fleet transition, and so we will do that. We have

got the -- all the outcomes of the '22 IRP from the solar resource procurements and battery procurements there; and so we will continue to transition the fleet, the same way we have with this Commission, looking at reliability, economics, and moving towards cleaner resources.

Q And also, are you familiar that some of the military bases also have a minimum energy availability requirement of 99.999 percent?

A (Witness Grubb) It is a what of that percentage? You said a minimum --

Q A minimum energy availability -- sorry, and it is 99.9999. It is six nines.

A (Witness Grubb) Okay.

Q Are you familiar with that requirement?

A (Witness Grubb) I am not. And when you speak about "energy availability," do you mean from the utility? From their own sources? I am just not sure what that standard is about.

Q Well, it depends -- it depends, of course.

A (Witness Grubb) Okay, yes. No, I am not familiar with it.

Q Okay. And are you familiar that the U.S. Army has some additional targets regarding microgrids by 2035?

A (Witness Grubb) Somewhat familiar. I don't know the details.

Q And is the company working to integrate those resources in this IRP or in the next IRP?

A (Witness Grubb) I am not sure on what the status of those resources are.

I do know, Commissioners, we have a -- Southern Company has a memorandum of understanding, that's nonbinding, to work with the federal government on these -- on their CFE goals. But I can't speak to where we are on microgrid projects. That's a different part of the company that's working on projects like that.

A (Witness Evans) I would also add that the customer-cited DER programs that we have proposed can fit into those requirements in several different ways and provide those benefits. And those capacity -- that capacity equivalents value, once those customers sign up, would be reflected on the resource plan.

Q One final question here, and thank you for entertaining me here. The '25, 2025 integrated resource plan, are you all using this filing as is for the 2025 IRP, or will you be re-running the Aurora capacity expansion model, redoing the transmission screening analyses? How much of the current is going to just be rolled over into the next IRP?

A (Witness Grubb) No. So, Commissioners, we will be updating everything in the tri-annual IRP in 2025

that we always do. Obviously, the outputs from this -- this request would be factored into that in terms of projecting our needs. But, no, everything will be restudied, as we always do, every three years.

Q Appreciate it.

VICE CHAIRMAN ECHOLS: Can we go back to the military base question? I know -- I don't know about the 99.9999, but I have -- I was recently at the Marine base, just doing a tour and looking at some of the energy stuff. And they are getting more aggressive with wanting, and the sergeant major told me, a 21-day resiliency plan.

It's different than when General Aycock came down here in 2000 --

COMMISSIONER MCDONALD: '14 --

VICE CHAIRMAN ECHOLS: -- 2014 under Obama's directive. The directives are a little bit different there. And the boxes we checked for them in '14 was just that it was adjacent, it was near, it was owned. Now it is getting more aggressive. We want access to it. We want -- you know, we want resiliency.

I mean, why couldn't we explore this with you all self-building for them, with them paying a portion of it to meet their goals, but our

ratepayers getting the benefit of the energy, except in an extreme catastrophic situation where they are completely, you know, out of power, and they don't want to be dependent on any outside sources? Why wouldn't we explore that relationship now in this -- in this time of emergency, as you are defining it?

MR. GRUBB: So my understanding is we are working with them on those types of projects under this MOU. I am personally not in that loop, but my understanding is we are working on those types of things with them.

So as we -- not in this update, because we -- we had a limited time to identify the resources, but going forward, we will continue to look at that. I don't personally do it, but my understanding is we have got groups of people that are working on exactly those types of things.

VICE CHAIRMAN ECHOLS: But instead of spending 100 percent of the cost of a battery storage system -- I mean, I know we are doing this at Robins and Moody; but on the others, instead of us spending ratepayer money for 100 percent, if we were able to only spend 50 percent and we gave the military, you know, the access to that during -- you know, during an extreme outage, that would save us money; right?

MR. EVANS: Commissioner, that exact example went in to inform our DER programs that we proposed here today. That exact shared savings model that you mentioned, where they have access to it for their resiliency needs but our customers are benefiting from it all other hours of the day and throughout the year, that's exactly how we have structured the DER program, with the military requirements in mind. Not designed specifically for them, but we think they absolutely can benefit from that program.

VICE CHAIRMAN ECHOLS: Great. Thank you.

MR. MAHAN: No further questions.

CHAIRMAN SHAW: All right. Thank you.

MR. MAHAN: Thanks.

CHAIRMAN SHAW: The Department of Defense and all other federal executive agencies.

MR. MCNUTT: Mr. Chairman, Commissioners, again, my name is John McNutt. I am an attorney with the United States Army, Fort Belvoir, here representing the United States Department of Defense and all other federal executive agencies. This is my first time in front of the Commission. Usually my colleague, Emily Medlyn, handles all of our Georgia matters. So I apologize if I am not

completely up to speed on the exact resource mix, so I will do my best.

I know we have been going for a couple of days, and we are all very tired and ready to go home, but I do have some questions for the panel. So if the Commissioners will indulge me, I will try not to repeat any questions that anyone else has asked, but since DOD has been mentioned several times, I do want to follow up on that very briefly.

CROSS-EXAMINATION

BY MR. MCNUTT:

Q You mentioned, Mr. Grubb, that you are aware of the existence of a memorandum of understanding signed by Southern Company with the federal government. Have you actually read that document?

A (Witness Grubb) I have.

Q You have? Okay. And you understand that that document is envisioned to encompass both Alabama Power, Mississippi Power, and Georgia Power together?

A (Witness Grubb) That's correct. It's a Southern Company MOU. That's correct.

Q Would you agree or disagree that the United States government is probably one of your top three customers in the state of Georgia?

A (Witness Grubb) I would -- when you total up

all the facilities, I would believe it would be, yes.

Q We are probably the largest customer, aren't we?

A (Witness Grubb) It wouldn't surprise me. I don't know. But probably right up there.

Q I think 25 federal agencies take service from Georgia Power. Does that sound about right to you?

A (Witness Grubb) It doesn't surprise me, no.

Q But you would agree the Department of Defense is clearly, within all the federal government, the largest customer, with our seven major military installations here?

A (Witness Grubb) Sure.

Q At the moment, the Department of Defense and the rest of the government have an Executive Order 14057 which mandates -- it is not a goal. It's a mandate -- that by 2030, 100 percent of our aggregate load, our total usage, has to be met by noncarbon resources. That includes nuclear, hydro, solar, wind, any other new technology we come up with. But it includes nuclear and hydro.

I didn't see anything in this update to address the government's requirement that we have a decarbonized load -- for our use, not the whole system -- by 2030. I see some battery at two Air Force bases. But why didn't

you include our requirements in your IRP, since we are one of your existing customers, not some potential future hypothetical customer in the future?

A (Witness Grubb) So, Commissioners, we are looking to serve all customers, and so the memorandum of understanding is to work with y'all on projects that can help you meet that goal, and we will. But at the end of the day, we have got to look at the Commission's policies and the Commission processes and, again, do it for reliability, economics, and transitioning to it.

So we don't -- unless there is a subscription program, we don't deploy specific resources for specific companies. So while we are going to work with the federal government on this, and we will work on programs and we will work on future resources, it doesn't factor directly into all of our planning. Because again, we are looking at the cost for all customers. And I know you are a big one, but we have still got to look at everything.

Q Well, what I heard in your opening statement at the beginning of yesterday morning was the word "extraordinary," I think five or six times. And I am not trying to be critical, but you mention, I think, that there are 51 potential projects that you are chasing, a third of which are in your service territory, in the

future. Was that the number I heard, 51; was that correct?

A (Witness Valle) Correct. Fifty-one customers looking for service.

Q Those are not your current customers. Those are future potential customers, correct, for economic development purposes? Which I am not criticizing. But those are not current customers; correct?

A (Witness Valle) So current is about -- about 14 are our customers. The other one are potential.

Q I am not trying to be combative. Please don't mistake my tone. I am frustrated that we are probably your biggest customer, and nothing in this IRP addresses any of our needs, which are substantial. Yet, I think this IRP could include a lot of resources that could help meet our needs.

So let's talk about those resources. I know that we are building a lot of solar coming up here in the next 10 or 15 years. I understand that. Why haven't you reached out to the Army to talk to the Army about putting more solar on Fort Moore, Fort Eisenhower, Fort Stewart, Hunter Army Airfield, along with battery storage? To my knowledge, and I work for the Army, you haven't even talked to us about those possibilities.

A (Witness Grubb) Yeah. So, again, I can't

speak to all the company personnel that are engaged in this effort; but, I mean, again, we have the MOU. We will work on that with the federal government. I don't personally do all those activities. But, again, we are looking at the entire customer base and the entire customer forecast.

So you are mentioning the new customers. We are always planning to meet the loads of existing customers plus new customers.

Q Commissioner Echols mentioned that it might be a good idea to put some of these battery storage programs on military bases. We are in the update right now, and you haven't even talked to us, and you can't even explain why. You just put up on Southern Company. I am talking to Georgia Power right now. You have solar right now in every military base in Georgia; correct? Been there for years?

A (Witness Grubb) I mean, I don't know about every base, but I know we have them on a lot of them. I just can't remember all the bases.

Q Well, the seven major installations all have Georgia Power-owned solar on them now.

A (Witness Grubb) Okay. I believe you.

Q Right. And you now have an update that includes battery for two Air Force bases but nothing for

the Navy or any of the Army installations; correct?

A (Witness Grubb) So we focused on the two largest solar facilities first.

COMMISSIONER MCDONALD: It has a Marine base, submarine base.

MR. MCNUTT: Submarine base and a Marine base. All right.

BY MR. MCNUTT:

Q But no battery for any of them in this current update?

A (Witness Grubb) Not in this update, that's correct. We are still looking at potential opportunities; and, again, Southern has that understanding. But, yes, it involves the retail operating companies, and we will work with the federal government on it. I just don't know what the latest status of those activities are.

A (Witness Evans) Yes. And to add to that, I do believe we are meeting with one of the federal branches within the next coming weeks to talk about our resiliency programs that are filed in this cases, the DER programs.

Q So if the Commission included language in its final order directing the company to come up with a plan to actually put more solar and more battery on the military installations, the company would comply with

that; correct?

A (Witness Grubb) Yes, we would.

MR. MCNUTT: I am going to bounce around, Mr. Chairman. I apologize. I had a long list. Half my stuff has already been covered, so I apologize if I seem a little scattershot here.

CHAIRMAN SHAW: No problem.

VICE CHAIRMAN ECHOLS: Well, let me interrupt you. The first question that I asked y'all yesterday was, how can we get more out of what we already have. And we haven't looked at the military, other than the two you have mentioned. But we haven't taken a comprehensive look, that you know of. We haven't talked to Jacksonville about -- you know, about their disgruntled portion of Vogtle that we might, could take out.

I just -- it almost feels like we are in a hurry, that we are rushing. And I just -- I just wonder, when we are -- when we are rushing, I wonder if we are more prone to make a mistake. And you have heard from some of the Commission. We don't want to make a mistake here.

So do you feel like we are rushing here?

MR. GRUBB: I feel like we had to act pretty quickly to take advantage of the forecast that we

see and to make sure that we can support the load from the customers that want to come to the state of Georgia. But we have identified good resources. Have we looked at every single one of them? No. Do we continue to look at them? Yes.

But we have got -- we have still got lots of needs beyond just '28. And so as we talk about the federal government and working with these projects, we have still got the opportunity to do that.

BY MR. MCNUTT:

Q This update, the current plan, it includes the -- essentially the construction of new combustion turbine, CT assets; correct?

A (Witness Grubb) That's correct.

Q And those are going to be dual fuel, natural gas and oil?

A (Witness Grubb) That's correct.

Q And I heard the word "hydrogen." And again, I am not an economist or a civil engineer, but my understanding is that it is possible to modify or build or buy combustion turbines that could run on hydrogen gas. Is that -- do you agree that that is an engineering feasibility?

A (Witness Grubb) Yes. I believe we had this question yesterday, and the machines that we are going to

pull at Yates are capable of burning hydrogen. It is the issue of and the economics of getting that hydrogen supply for that CT.

Q Right. And that's what I want to ask you about right now, because that's a critical component. Without putting any additional cost on any other ratepayer, other than the federal government, let's say the Department of Defense specifically. If the Department of Defense came to you and said, we have got to decarbonize, and hydrogen gas is something that can be burned, that we consider to be carbon free, right, because it is hydrogen, and we understand that hydrogen gas at the current market price is ten times the cost of natural gas for just the fuel; right? But we are willing to pay that premium so that we can say that we are -- we decarbonized our portion of the load.

Would the company be willing to work with us to say, okay, one of these turbines, we'll have it run on hydrogen gas, and the Department of Defense will pay the premium for that extra cost, that delta, between natural gas at $5 a million therm, or whatever it is, dekatherm, compared to hydrogen gas, would the company be willing to do that?

A (Witness Grubb) So under the MOU, we would have those discussions, and we would -- if we -- and we

could work with y'all. If it was a project that we felt we could bring to this Commission and it would benefit you and other customers, we would be open to those discussions.

Q Right. And would you agree that hydrogen gas is controversial in the sense that blue hydrogen is generally produced using fossil fuels? Would you agree that you -- that you understand that concept?

A (Witness Grubb) I understand there is several colors of hydrogen. I believe that's correct. But, yes, I think it is not just hydrogen. It is the amount -- the manner in which you source that hydrogen that's important.

Q Right. And that green hydrogen gas, in a perfect world, is manufactured using solar or wind for the electricity to actually make the gas?

A (Witness Grubb) Yes. That's my understanding, yes.

Q And you -- you, Georgia Power, you haven't put any money into potentially developing a hydrogen gas manufacturing facility? You have essentially ignored that source of a carbon pollution free fuel; correct?

A (Witness Grubb) Are you talking about producing hydrogen gas?

Q Yes, to burn in your turbines.

A (Witness Grubb) Yes. So I know we had the test burn at Plant McDonough for hydrogen through that machine. But as far as generating gas, I am not -- I am not familiar with that. I don't know if someone at the Southern level is doing it or not. We are not usually in the gas production business, from an electric utility standpoint at Georgia Power. But I don't know what our status there is.

Q Right. But from a reducing your carbon footprint concept, that would be something that might be helpful. Set aside the cost. I am talking about just to reduce your carbon footprint. You would be capable, theoretically, as a billion-dollar company, to invest in a hydrogen gas production facility if it could reduce your carbon footprint; correct?

A (Witness Grubb) Yes. And so, we have got the hydrogen microgrid project that the Commission approved last year to start giving us some experience with hydrogen. I just can't speak to every single effort that Southern Company is looking at from an R&D standpoint on, you know, carbon-free energy and those types of sources. Not saying we are not doing it. I am just not involved in that, and I am not aware of what our efforts are.

Q And you would agree with me that, obviously, hydrogen costs a lot more than natural gas in the current

market environment; correct?

A (Witness Grubb) That's my understanding, yes. That's correct.

Q But that it takes leaders to start the process of trying to reduce cost by getting to it to scale?

A (Witness Grubb) Well, like any technology development, it takes everybody to -- it takes effort.

COMMISSIONER MCDONALD: But what you are suggesting is that they go to hydrogen, they come back to this Commission to get the revenue to produce that hydrogen going to the ratepayer; is that correct?

MR. MCNUTT: I am not suggesting that.

COMMISSIONER MCDONALD: You ought to sit in this seat sometime, you know.

MR. MCNUTT: Right.

COMMISSIONER MCDONALD: When you talk about converting to hydrogen, and tomorrow I have to write a check to the IRS for my payment toward the -- my income tax, and as an American citizen, taxpayer, you know, you sit over here, it is a little different story. And you have got John Kerry, part of this administration, flying around the world in his own private plane, and you talk to me about carbon?

MR. MCNUTT: Commissioner McDonald, I can't speak to the rest of the government. What I can speak to is we don't want other ratepayers to subsidize the government's energy requirements, and certainly, my job is to protect the fisc. I have been doing that for many years, and I understand.

We want the federal government to spend a reasonable amount of money for carbon-free electric generation. We obviously don't want to spend ten times what the market is. But there is a delta to get down to where we need to go.

I do appreciate, obviously, protecting taxpayer dollars, and we don't want to overspend for electricity. But technology does have to start somewhere. And then, ultimately, these costs will be reduced. The more we can build it, the cheaper it will get over time.

VICE CHAIRMAN ECHOLS: Yeah. You mentioned the sub base. Commissioner mentioned the sub base. I mean, just 12 miles, as the crow flies, from the sub base there is a hydrogen production facility that Plug Power runs that they have just expanded with lots of electrolyzers. So the fuel is right there. If, say, we wanted to do something at the sub base where they paid more, it just doesn't sound like we

have explored all of these options.

MR. GRUBB: So we can explore those options. I think, in this case, we have talked about the critical nature of the timing. I am not sure we can get it done and avoid the resources we are identifying here. But, Commissioner, we are always willing to work with customers. Especially the ones we have got the MOU with. So we are definitely going to work with you how we can.

BY MR. MCNUTT:

Q Let me ask you about pump storage, because I know we are talking about -- we are talking about a five-year update here; right? This is the window we are looking at today, is five years?

A (Witness Grubb) Yes. So for the next -- yes, through 2028. That's correct.

Q 2028. So my understanding is that Georgia Power has been enthusiastic about accepting Department of Energy grant money -- I think it is 2.7 million -- for a pilot program to determine if the Rocky Mountain pump storage -- the Rocky Mountain hydroelectric facility could be converted to pump storage. Are you aware of that?

A (Witness Grubb) I am not, but I know Rocky Mountain is already a pump storage hydro facility that we

-- that Oglethorpe actually operates and we own a portion of. So I don't know the status of the DOE, but Rocky Mountain has already been pump storage.

Q I misspoke. I meant Bartletts Ferry.

A (Witness Grubb) Okay. Yes. Just wanted to make sure I was right.

Yeah. So Bartletts Ferry, which we have -- Commissioners, we are modernizing 1 through 4 that we got approved in the 2019 IRP. But I do know that we are engaged on the DOE front.

Q Right. And my understanding is that Rocky Mountain produces about 1,000 megawatt from three turbines now. Is that your understanding about that?

A (Witness Grubb) Rocky Mountain would. Bartletts not.

Q Right.

A (Witness Grubb) I don't think Bartletts Ferry is --

Q Bartletts is 173. I am going back to Rocky Mountain.

A (Witness Grubb) Okay. Just want to make sure I was -- we are talking about the right one.

Yes. So Rocky Mountain is quite large, yes.

Q Now, Alabama Power spent years trying to develop Chandler Mountain as a pump storage facility in

Alabama. That was going to be 1,600 megawatts. Are you familiar with that projects?

A (Witness Grubb) I am not familiar with the details of the project, but I know they were working on it; and it did not get approved to move forward, is my understanding.

Q Correct. So just to give you some background, the Alabama Public Service Commission preemptively stated they were not going to support it because of a cost problem. And ultimately, Alabama Power decided to pull their permit from FERC for that project, so that project is dead.

A (Witness Grubb) That's my understanding.

Q Right. Is there any legal or scientific or engineering reason why Georgia Power couldn't have picked up where Alabama Power was and acquired that asset or come to a deal with Alabama Power, a PPA with Alabama Power, to finish that? Even if Alabama ratepayers wouldn't pay for it, that Georgia Power could have gotten that 1,600 megawatts through pump storage, which would have been ready by 2030?

A (Witness Grubb) Well, I think the same issues on cost would apply to Georgia Power just like it did to Alabama Power. So I can't speak to what Alabama wants to do with that project. It could be that they want to go

at it again later. I don't know.

So they didn't approach us. I am not sure we have approached them. But, again, pump storage hydro is a great resource, but it is hard to build new ones.

Q You talk about cost. Wouldn't it have been cheaper just to keep coal plants running for the next 50 years instead of building Vogtle 3 and 4? Aren't those nuclear kilowatt hours more expensive than if you just kept running coal plants forever?

A (Witness Grubb) So from a kilowatt hour standpoint, the most efficient units we have on the entire fleet are the Vogtle units.

COMMISSIONER MCDONALD: You can't speak out of both sides of your mouth here now. You have got to -- you want to do one or the other. How you want to do it?

BY MR. MCNUTT:

Q Well, at some point, you are running coal in this PPA because it the cheapest way to get power; right?

A (Witness Grubb) So for the Mississippi PPA?

Q The Mississippi Power one.

A (Witness Grubb) Again, it is from their system. The value of the Mississippi PPA is the fact that it is existing resources that we can have available to serve the earlier need years.

Q But you would agree that different resources cost different amounts. They are not all nine cents a kilowatt hour to run; correct?

A (Witness Grubb) Absolutely. Every resource has limitations or lack of limitations. They have got different dispatchability. That's why a diverse fleet is so important.

Q Batteries, for example, are extremely expensive compared to just running gas plants 24 hours a day; right?

A (Witness Grubb) You are talking about upfront cost, or which cost are you talking about?

Q BESS, the battery electric storage systems. That's a lot; right? The cost to install those facilities? But we are doing it anyway, because that's the right thing to do; correct?

A (Witness Grubb) Well, yeah. We are having to add resources, though. That's why we are identifying -- you asked compared to a gas plant. I didn't know if you were referring to an existing gas plant or not; but, yeah, we have identified those as resources we need to deploy and can deploy.

Q What -- what is Georgia Power's plan for future pump storage, other than this pilot project at Bartletts Ferry? Do you have any ambitious plans to build

1,000 megawatt pump storage anywhere in the state? We have got 15 hydroelectric dams now.

A (Witness Grubb) We do.

And, Commissioners, when we look at our technology screening applications and when we look at our planning process, pump storage hydro does not screen in from a cost or -- you are right. Cost is not the only thing. But when we look at it, it does not show as a dominant solution to deploy. It doesn't mean we can't look at it. But that's why it is not on the forefront of what we are looking at. It is challenging.

The ones we have are great, and they have some value. But when we look at deploying resources, pump storage hydro economically does not filter in as one of the best economic choices for deploying in the state.

MR. MCNUTT: Mr. Chairman, may I have a moment to consult Mr. Hewitson on a document?

CHAIRMAN SHAW: Go ahead.

BY MR. MCNUTT:

Q Mr. Grubb, I am looking at a document called Canada Technology Assumptions. It is marked as a trade secret, so I can't mention the numbers. But there are a bunch of different technologies on here. Are you familiar with this document? Can I refresh your recollection?

A (Witness Grubb) Yes. Is it from this filing?

Q It is Table 2, yes. Can I just show it to you?

A (Witness Grubb) Yes, sure. Table 2 in the --

COMMISSIONER MCDONALD: You can ask the Chairman if you can show it to him.

MR. MCNUTT: I am sorry, Mr. Chairman. Permission to approach the witness?

COMMISSIONER MCDONALD: Go ahead.

CHAIRMAN SHAW: Go ahead.

MR. MCNUTT: Thank you.

BY MR. MCNUTT:

Q Mr. Grubb, now that we are both looking at the same document --

A (Witness Grubb) Yes, sir.

Q -- without revealing any trade secrets, can you explain what document you are looking at?

A (Witness Grubb) Yes. So this is the Canada Technology Assumptions that go into our resource mix study that is developed based on a lot of information that Mr. Bush and his group look at. So these are the performance and cost factors of the resources that we model in the Aurora model, that we have updated -- we update every year we run these models.

Q You mentioned two or three minutes ago before I asked about this that you told the Commission that pump

storage just didn't fit the profile. It wasn't economic. But isn't it true you didn't even put it in this table? You didn't even evaluate the numbers?

A (Witness Grubb) So Mr. Bush can help me here. But this is the technology assumptions that we actually modeled. And so, we have got an entire process at the company where we -- we screen out technologies based on cost and other factors before we put it in the model.

And so, Commissioners, you will recall from the 2022 IRP and prior ones, we have kind of got technology -- technology application standards, I think is what we call it now. It used to be the old generation technology data book. Where we would look at the cost of all those resources, but we screen it before we submit it to the models.

And so, this would indicate that pump storage hydro was not in the models because it was less cost efficient than the resources we did model.

A (Witness Bush) I would just add, the other thing that we keep in our models, Commissioner, are generic repeatable resources. And pump storage is a very custom -- it is not -- there is no location that you could ever consider it generic or repeatable with that same configuration. They are all very unique. Very different. Highly capital intensive.

And recently -- he mentioned maybe a 2030 in-service date. That it would -- that is not a possibility. Not a possibility if we began today in Georgia. Nor if, for some way, Georgia could have taken over what Alabama was doing. It would be much closer to a 2040 in-service end date. So it is a long lead time, highly capital intensive project.

A (Witness Grubb) And, Commissioners, we are talking about new pump storage hydro. I think Mr. McNutt mentioned DOE funds for Bartletts Ferry. That would be looking at an existing hydro facility pump storage, which is different.

And so to Mr. Bush's point, it is not generic, and we don't model it. We will study that. But we were talking more along new pump storage hydro like the Chandler Mountain that he mentioned at Alabama.

Q Right. So is it fair to say, then, that the company has effectively written off new pump storage as a resource for the next 20 years? Is that a fair statement?

COMMISSIONER PRIDEMORE: Mr. McNutt, let me give you a Commissioner's perspective, as you keep talking about pump storage hydro. So we -- we are unlike other states in that we go through an intensive integrated resource planning process every

three years.

And because we update that plan so frequently, it gives us the opportunity to over -- over time, look and evaluate. Consider it like gates. Have you -- have you ever went out -- have you ever been on a farm where you had to go out and feed animals and you had to, like, go through a series of gates because you have got to move the cattle to be able to get into different sections of the farm to be able to eat? Have you ever done anything like that on a ranch?

MR. MCNUTT: I worked on a ranch for six months in Miles City, Montana, yes.

COMMISSIONER PRIDEMORE: There you go.

MR. MCNUTT: So I have moved cows. Not on a horse. Usually on a four-wheeler.

COMMISSIONER PRIDEMORE: So you get through a gate and you close the gate, and you go that's just not economical and right for us right now. That's where pump storage hydro is. In terms of future technologies, whether it is hydrogen of any color of the rainbow, those are emerging and coming. But in the same respect that I would want -- I wouldn't want them to pay employees to model new coal development.

Do you know what I mean? It is -- you go through a gate and you realize what is effective, and then you utilize that and the staffing resources that they have to get us to the most effective outcome. That's all.

MR. MCNUTT: I appreciate that, Commissioner. Absolutely.

I am going to wrap up here in just a minute, Mr. Chairman.

BY MR. MCNUTT:

Q I wanted to ask you about your projected energy sales. I am looking at a chart here in gigawatt hours that shows that from 2012 to 2024 that the company's actuals have been around 30,000 gigawatt hours a year. Would you generally agree that those numbers are about accurate?

A (Witness Grubb) Do you have that information or the document that you are looking at?

MR. MCNUTT: Mr. Chairman, permission to approach?

CHAIRMAN SHAW: Yes, sir.

COMMISSIONER MCDONALD: You did learn something, didn't you?

MR. MCNUTT: Like I said, Mr. Chairman, Commissioners, this is my first time before the

GPSC.

BY MR. MCNUTT:

Q Now that I have shown you the document, do you have it in front of you, Mr. Grubb?

A (Witness Grubb) Yes, we do. It is page 6 in the load forecasts of the main filing in October.

Q So would you agree with me that the actual gigawatt hours from 2012 to 2024 are about 30,000 gigawatt hours on an annual basis?

A (Witness Grubb) So say it again, are you talking about energy? Did you say 30?

Q Correct. From 2012 to 2024, your gigawatt hours in sales have been flat?

A (Witness Grubb) I'm sorry, I was on the wrong one.

A (Witness Bush) Excuse me. Mr. McNutt, is it 1.2.3-1?

Q Yes.

A (Witness Grubb) So this is commercial energy sales; not total.

Q Correct.

A (Witness Grubb) Okay, yes, sorry, I was on the wrong one. Yes, so that one. Yes, so that's correct.

Q So sales have been flat for the last 12 years. Is that a fair statement?

A (Witness Evans) For that class of customers?

Q For commercial.

A (Witness Valle) Yes, for -- that is a correct statement, yes.

Q Okay. And then -- and I am not trying to be facetious, but this -- this forecast projects, essentially, a doubling of that in the next four years. 2028, you are projecting 60,000 gigawatt hours in sales to commercial?

A (Witness Valle) Yes, that is correct.

Q All right. You are going to double your energy sales to commercial customers in the next four years?

A (Witness Valle) That is the nature of the request. It is truly unprecedented. Yes, that is correct.

Q Well, in four years I hope to see you here again and we can ask you how accurate that projection was, because for 12 years it has been flat, and now you are projecting to double it --

A (Witness Grubb) We'll be here.

Q -- in the next 96 months?

A (Witness Grubb) Yes. This Commission will get to see. Every year we will update it.

Commissioners, as we talked about, these customers, these commercial customers that we have got in

this forecast are multiple times larger than what we have won in Customer Choice in some years. So it is just a change in the economy and the types of commercial customers that the whole nation is seeing.

CHAIRMAN SHAW: Is it true what I have heard about one client, one potential client, or -- I don't know. It may be an existing client that you have already won. But it is a data center with multiple locations that the total load is somewhere around 1,000 megawatts?

MR. GRUBB: That is correct.

MR. VALLE: Some of them, even larger.

CHAIRMAN SHAW: Excuse me?

MR. VALLE: Some of them even larger than 1,000 megawatts.

CHAIRMAN SHAW: For one customer?

MR. VALLE: One customer, sir.

MR. GRUBB: And so, again, so just to hit that, when we look at that customer and we look at the cost and the pricing, we capture all of that in there and the cost it takes to serve that. But that's why the opportunity to put downward pressure on rates, these loads are so large, that it gives you a lot bigger base to spread those costs on. Because of the magnitude.

CHAIRMAN SHAW: Hopefully, they are going to provide a lot of jobs, too.

MR. EVANS: And you were right, Commissioner. That was a project, not speculative, but that we have won.

MR. MCNUTT: Mr. Chairman, I want to thank the Commission for its time today and for indulging me in my questioning. I appreciate the Commission taking the time to listen me. Thank you so much.

CHAIRMAN SHAW: Good to have you. Welcome to Georgia. And for providing a little entertainment today.

MR. MCNUTT: Sir, I was going to break out the confetti, but my colleagues here with SEBA said not to do it. It would be too dramatic.

CHAIRMAN SHAW: Walmart? Afternoon.

MS. EATON: Good afternoon. This is also my first time here.

CHAIRMAN SHAW: Welcome.

MS. EATON: But this is my hometown, so I feel at home already.

CROSS-EXAMINATION

BY MS. EATON:

Q I just have some mostly clarifications from the questions that you have been asked and really appreciate

your time and attention to all the questions the intervenors have asked. All of my questions are coming from your direct testimony. So if you have that handy, I am going to refer to the pages within your direct testimony.

A (Witness Grubb) Yes, ma'am, we have them. Let us flip to that real quickly.

Q Sure. I know you have got a lot of paper there.

A (Witness Grubb) Yes.

Q The first bit of questions is related to Section 5 of your testimony about the DER and demand response solutions. And on page 42, you described DER customer co-location programs where Georgia Power would "own, operate, maintain, and control a dispatchable DER of ten megawatt or greater at customer premises." Do you see that?

A (Witness Evans) I do.

Q Okay. On page 42, line 16 to 17, you referenced a program agreement between the co-location customer and Georgia Power. Do you have an idea of the number of years that program agreement would be for?

A (Witness Evans) Sure. So the co-location program is the program where Georgia Power will own that asset. It will be dispatched for capacity and energy

benefits, just like any of our other resources; but it will also be available for that host customer, that participating customer's resiliency needs. So as such, that it will be utilized by the system for the life of the asset, the contract will be for the life of the asset.

Q So it is the life of the particular asset that's dispatched at the customer site?

A (Witness Evans) That's correct.

Q Do you already have customers, without naming anyone, do you already customers who have indicated to Georgia Power that they are interested in participating in this program?

A (Witness Evans) Yes, we have customers that are interested. Various stages of development and things like that. But, yes, we are beginning to have those conversations a little bit more concretely. We have had conversations preliminarily as we designed the program. But as we have developed it and filed it, we have had more; and customers are interested, yes.

Q Okay. Thank you.

At page 43, lines 7 to 25, you are describing your DER customer-owned program where Georgia Power will operate and control a customer-owned new dispatchable DER of 1 megawatt or greater. How much notice would Georgia

Power plan to provide to these customers of Georgia Power's intent to use the customer-owned DER?

A (Witness Evans) One second. I don't believe that was outlined in the tariffs that we filed last week, but let me reference those real quick. Yeah, we have not -- that would be something that we would outline later in the agreement that was referenced. We will give some notice to customers; but, again, those assets are for the term of that shortened agreement.

Now this program that was referenced, the customer-owned program, won't be for the life of the asset. That will be for a shorter duration through 2031. At that point, we will reevaluate those contracts and the benefit that those resources can provide to the system.

So we will have some notification to the customer, but those assets during the contract period will also be under the control of Georgia Power.

Q Sure. And I think you were trying to answer two questions at once that I had. You said that you will outline the notice provision in the agreement. Do you have a general idea, like would it be half hour? One hour? Hours? Something like that? Or really, almost moments' notice sort of thing?

A (Witness Evans) Yes. I am not sure if we finalized that right now. Typically, with these programs

that we have currently available, we do provide some notice to the customer.

Q Okay. And for the programs you have on-line right now, what sort of notice? Like an average of amount of time we are talking about?

A (Witness Evans) Let me look.

Q Thank you.

A (Witness Evans) So for the DER Demand Response Credit rider that's currently available for customers that are also enrolled in the Resiliency Asset Service Tariff that was -- both of which were approved in the '22 IRP. On the tariff we say, "The company will notify the customer at least 30 minutes prior to each time the customer must provide demand reductions via that asset."

Q Okay. Thank you.

And then you were referring to their program agreement again for this particular DER customer-owned program. I think you said the program agreement would be through 2031. So it is a shorter duration contract. So it would be like 2024 to 2031, something like that?

A (Witness Evans) Whenever the asset is available and gets certified by the Commission. Again, both of these programs, the company-owned program and the co-location program, are going to be structured as supply-side assets. So individually, these resources

will come back before the Commission for certification, and based on that and that COD date of the asset would dictate the contract length.

Q Okay.

A (Witness Evans) And because different assets have different availabilities, right, and things like that, we are not structuring a minimum requirement or a minimum notification, because different types of resources can provide different benefits, and that might vary. Not significantly, but we are allowing some flexibility in there given the contracts and the different types of resources that can fit under it.

Q Sure. But you would expect that the program agreement itself, with that particular customer, would provide that sort of notice parameter?

A (Witness Evans) Absolutely.

Q Okay. On page 46, you start a discussion about the proposed curtailable load program; and on page 47 at line 19, you say, "Georgia Power will require demonstration on a regular basis." How frequently is a regular basis that you are referring to there?

A (Witness Evans) Sure. So on the tariff that was filed last week, we have a Section 4, Demonstrations, and that reads, "The customer will be required to demonstrate the ability to achieve their contract at firm

demand level on an annual basis."

Q Okay. And demonstration, can you just explain what it is you would be asking the customer to do?

A (Witness Evans) Sure. It would essentially be a response like they were contracted to otherwise. The demonstration is to ensure, even though we might not, and hopefully do not for prolonged periods, have reliability events which require the program to operate, we need to ensure that that load still is there and the customer is able to react and participate in the program. So that just ensures that that resource for which we are relying on from a demand reduction is there every year.

Q And that demonstration would be something that you have coordinated with that particular customer so that, you know, they are ready for it?

A (Witness Evans) We will give them the same notice that we would under an otherwise event.

Q But they would know that it is a demonstration, that it is not actually being called upon for some event?

A (Witness Evans) Probably.

Q Maybe not?

A (Witness Evans) Yes. Their response should be the same either way.

Q Sure. And then a little bit further on page 47, lines 20 to 21, you say, "There will be updated

compliance incentive." Can you tell us a little bit about -- more about that?

A (Witness Evans) Can you repeat that page and line again? I was flipping back and forth between the tariff and the testimony.

Q Sure. It is page 47, lines 20 to 21. You said, "There is an updated compliance incentive in this curtailable load program." Can you just explain what you mean?

A (Witness Evans) Sure. I will flip back to the tariff now.

Q Sure.

A (Witness Evans) So under the compliance incentive portion, this talks about if a customer fails to respond to an event or -- so I can read it. "If the customer fails to comply and does -- and meet their firm demand level during a demand response event or a demonstration, then the company may enforce a compliance incentive or terminate the agreement. A compliance incentive will be determined based on the demand response value lost by the company."

So again, because we are putting this program on the resource ledger, there is a value there that we are anticipating receiving from these customers' reduction in load during critical events.

So if we have been paying a customer under this contract to provide that benefit to the system and it does not materialize, then we have essentially been paying for something we didn't receive; right? So in the event that they did not perform as contracted, we would enforce a compliance incentive that provided the difference between the value we did receive and what we paid.

Q Thank you.

Again, in relation to the curtailable load program, you reference multi-year commitments. How long would you expect those commitments to be?

A (Witness Evans) Under the term of service on the tariff, the CL agreement would be based on a six-year term of service.

Q Thank you. You were asked many, many questions about the additional sum. I am not going to reiterate those. But did you consider not including additional sum with the PPAs as part of this 2023 IRP update?

A (Witness Grubb) No, we did not. We were looking to be consistent with the 2022 IRP.

Q Are you required to include the additional sum with the PPAs?

A (Witness Grubb) So we are allowed by law. So it is not required, but it is something that we have

always asked for on PPAs and also DSM and other aspects of the plans.

Q Okay. I want to turn now to some questions about modeling. You have also been asked a lot of questions about modeling, so I am not going to belabor those. When was your new probabilistic model developed?

A (Witness Valle) It was developed between December and early days of January of 2023.

Q Between December --

A (Witness Valle) December of 2022.

Q -- '22. Okay.

A (Witness Valle) Yes. And early January 2023.

Q And that is a proprietary model, you said?

A (Witness Valle) Yes. It was developed in-house.

Q Okay. Now, earlier -- I think it was you, Mr. Valle -- you were talking about how the customer information related to this modeling. You gathered information about customers who have identified sites within Georgia. They have engaged Georgia Power for electric service. And then the customer gives Georgia Power a ramp-up information.

Is there any other information those customers are providing? Or is that -- those are the three bits of information you were referencing?

A (Witness Valle) Those are the basic pieces. There is also -- there is also like the class, like if it is residential, commercial, the segment. There is some other -- other identifiers and things that go into a model, but they are derived by the nature of the business.

Q Okay. You also referred to 17,000 megawatts in the pipeline. How do you -- how did you determine what was in the pipeline versus, you know, the 7,000 that you are sure of? I am trying to understand, how did you even come up with the 17,000 in the pipeline in the first place?

A (Witness Valle) Absolutely. The 17,000 megawatts, it is a -- it is the amount of megawatts that we are tracking -- that we were tracking at the time of developing this forecast. So there is a dynamic tool that, you know, as a new customer approaches Georgia Power for electric service and have provided all the information necessary, it gets added into that tracking system, and it becomes part of the total.

Q And so is the 17,000 -- are those -- that's the total number of megawatts for these particular new customers. But then of that, you were saying like 7,000 of that would be the customers who have decided to site in Georgia, decided Georgia Power is going to be their

provider, and have engaged you for electrical service and provided you with the ramp-up plan?

A (Witness Valle) Correct. Of the 17,000 megawatts, around 7,000 is the size of the external adjustment that we are including in the forecast.

Q Okay. Thank you.

On page 19 of your direct testimony, at lines 15 to 17, you referenced a Monte Carlo simulation and analysis. Is this the analysis about which you were testifying in response to questions from Ms. Whitfield and Commissioner Pridemore yesterday?

A (Witness Valle) Yes, that is correct.

Q Okay.

A (Witness Valle) So the model -- again, the model, the Monte Carlo model is designed to answer two questions: First, will the customer become a Georgia Power customer? Yes or no. And then if the answer is "yes," then we assess the load realization amount and include some potential delays.

And so, in order to assess and evaluate all of these combinations, there is a mathematical technique, very widely used for these situations. It is called Monte Carlo, and that's what we use to inform the load for our customers.

Q Okay. That was the one wherein the results referenced as P50 were statistically most likely?

A (Witness Valle) So the result of a Monte Carlo simulation, regardless if it is load or something else, is a distribution of outcomes. That's what we have been referring as the range. And so, it is one output in the form of a distribution.

Q Okay. And that was a result of you running the Monte Carlo simulation and analysis for this IRP?

A (Witness Valle) Correct. One of the points along that, yes.

Q Now, I want to jump a little bit and talk briefly about EV growth. On page 17, at lines 3 to 5, Georgia Power identified large load economic development projects. One of which you say in that paragraph, or that sentence, is the EV industry. And you talked a lot about the data center load and that being a large -- about 80 percent of the load. And then I think there at Figure 1 on page 17, is that showing the new load?

A (Witness Valle) Yes. So Figure 1 on page 17 correspond to the amount of customers that have selected Georgia Power by year. It is meant to represent and illustrate the changing trend that we have seen from pre-2021 until what we have today.

Q And would that include the 7,000 megawatts of

the customers that you say you won?

A (Witness Valle) Yes. So these are the customers won.

Q Okay. Got it.

A (Witness Valle) Yes. And so the 7,000, it is a -- it is made up of customers that we have won and prospective customers, as well.

Q Okay. Can you put a percentage on the new load that is represented by the EV industry?

A (Witness Valle) Not off the top of my head, but we have that information. We can provide those.

A (Witness Grubb) And to be clear, when we talk about the EV industry, we are talking about manufacturing of EVs.

Q Okay.

A (Witness Grubb) Not just EV usage for charging. So that's in the forecast. But what we are talking about here in terms of the change we have seen in the economy, it is more the -- it is the EV car manufacturing facilities more than EV charging.

Q Okay. Thank you for that clarification, because that was not completely clear.

So would you have information about the percentage of the EV car manufacturing separate from the EV charging load in your forecast?

A (Witness Valle) The car manufacturers, yes. We track that individually. For the EV charging load, the way that we forecast the EV load is the load that -- is the energy that goes into the car. We don't make the distinction by charger. We just identify the charging patterns; and we make sure that we capture that, that piece into the forecast.

Q And is that information included in this 2023 IRP update, or it is not?

A (Witness Valle) Yes, it is.

Q Okay.

A (Witness Grubb) It is part of the total forecast; and it is an external adjustment, too, I believe.

A (Witness Valle) Yes, correct.

A (Witness Grubb) So that's how we know the EV charging part of the load. So it is somewhere in a model or data request that we can track that down for you.

Q Okay, sure. That would be information -- it would be important information to have in that if the EV charging load changes substantially, it is something that could change substantially. As the fleets become electrified and you do have very large EV charging fleet hub needs, that could potentially impact your load forecast. Would you agree with that?

A (Witness Grubb) Yes, we do. Sorry. And I think one other point to make is, you know, the need for generation is always based on what we need for the peak. So rate design and other things can help dampen the need or the contribution from that to the peak. But, yes, agree that that is part of the forecasts.

Q And it can impact future load forecast to the extent that large swaths of companies, like Walmart, electrify their fleets and have need for an EV hub to charge their trucks that are delivering goods and services.

A (Witness Valle) Yes. That is part of the forecast. We have --

A (Witness Grubb) That's right.

A (Witness Valle) We have a light-duty section of the forecast, and we have a medium-to-heavy duty, which would be capturing what Walmart would be adding to the system.

Q And that's actually information you could kind of break out so it would be a little bit more visible to those of us that want to see it?

A (Witness Valle) Absolutely. I think it would be trade secret; but under the right disclosures, we can share it, yes.

Q Sure. Thank you.

I want to talk briefly about your carbon dioxide forecast assumptions, and mainly to clarify some things that I believe I heard yesterday. I was trying to take good notes, but just want to make sure. I think yesterday you told us that for your 2023 IRP update you used the same CO2 forecast assumptions that you had with your 2022 IRP; is that right?

A (Witness Grubb) They were similar. They weren't exactly the same. We had, I think, two more cases in the '22 IRP that we did not include in this one. But it is similar in that we look at a range of scenarios to capture carbon pressure.

A (Witness Bush) Excuse me. When you say, "the carbon forecast," do you mean a carbon price forecast or a carbon production forecast? Could you clarify what you mean there?

Q I believe it is the production forecast. You were speaking about having a carbon tax -- could be the price forecast, really. Because you talked about a carbon tax in 2025 for the resource mix study; is that right?

A (Witness Grubb) Yes. So we have got some questions around the timing of carbon. But that's correct. So when you look at the resource mix study and those scenarios, you are right. That's a -- that's

either a price or a -- a limit on emissions that we model to look at different carbon pressures. Yes.

Q Okay. So what I wanted to confirm is that I think you said that the CO2 tax was put in 2025 for the resource mix study but in 2030 for the economic study. Was that right?

A (Witness Grubb) I -- I would have to go verify that. Just like yesterday, I didn't verify it last night. I think the -- so I think the economic analysis was a little earlier vintage, so it may have the earlier carbon date than the expansion plan, just on the energy portion of that. So I would have to verify it. But -- I just can't remember what the start date in the expansion plan is for carbon, but I think it may be '30. I just can't remember. I need to confirm that.

Q Okay. And so that's something you can confirm for everybody?

A (Witness Grubb) It is probably somewhere in here.

Q Okay.

A (Witness Grubb) I just can't -- I can't find it.

Q I wanted to make sure, right, I understood what you were talking about yesterday.

A (Witness Grubb) Yes, ma'am.

Q What is the difference in the two years? Why select the two different time periods?

A (Witness Grubb) So each year when we do our system planning process in the scenario planning, you are usually looking at carbon a few years out; and so we usually, as we go year to year, we just move that out generally. It is not based on any certain rule or any certain proposed bill.

So we are just looking at the time that we think you could, in the model, start responding to it. And it will differ sometimes on the cases. So I would -- I just can't remember what that year is. My apologies.

Q Sure. No problem.

Would you agree that there is still a significant pressure to reduce carbon and to help your commercial and industrial customers meet sustainability goals?

A (Witness Grubb) Yes, I would. And that is -- that is exactly why we have continued to evaluate those scenarios and that carbon pressure, both in the economic analysis and the resource mix study. And again, as we have talked about, that's a -- that's one of the drivers in the fleet transition, along with reliability and economics.

Q And I believe in response to some questions

from Mr. Dunbar yesterday you said you were generally familiar with some customers' clean energy goals but maybe not in specific; is that correct?

A (Witness Grubb) That's correct. We didn't know specific ones, but we know many of our customers do. And as we are in discussions with those customers where they are looking at the state or anything like that, we are often in discussions with them on the programs that we offer and how we can help them with those goals.

So, yes, we just don't know specific customer goals. There is a lot of them, so...

Q Sure. I believe there was some testimony in the -- from the Commercial Group, and that was the director of energy services from Walmart, Steve Chriss, in the 2022 IRP. And Walmart, in September of 2020, made a public announcement that its sustainability goals are to be supplied 100 percent by renewable energy by 2035 and zero CO2 emissions in its own operations, including fleet transportation vehicles, without offsets, by 2040.

Had you heard that information before?

A (Witness Grubb) Not that -- I mean, if it was in the 2022 IRP, it just means I can't recall. But, yes, so those are some of the drivers behind -- those are the drivers behind the subscription programs that we do and get approved by the Commission on our renewable

solicitations.

Q And you are willing to work with customers, like Walmart and other customers in the commercial and industrial area, to help them meet these sustainability goals?

A (Witness Grubb) Absolutely. Always.

Q Do you have any stakeholder meetings currently with the C&I customers related specifically to meeting their carbon emission reduction and sustainability goals?

A (Witness Grubb) So I know we have a lot of key account reps in the company, initial accounts reps, that work with those different customers. I am not sure of the discussions they are having. But we do know that there is a lot of customer need for those types of programs that we take into account, but I am not personally involved in those conversations. But I know we are constantly having them, is my understanding.

Q Sure. Would Georgia Power be interested or would you favor having or starting stakeholder engagement meetings with C&I customers to kind of generically talk through ways where all the different customers could meet these sustainability goals?

A (Witness Grubb) I believe our customer group is already having those conversations with those customers.

Q I know Walmart is a participant of the Georgia Power Renewable Energy Development Initiative Program. Is that one of the entities that would be talking about these sort of goals?

A (Witness Grubb) So the -- the REDI program was a subscription program for the renewables.

Q Okay.

A (Witness Grubb) So that's one of the ways in which Walmart is able to get those renewable energy credits towards its goals. So I know that there is a -- again, our customer reps understand the sustainability goals of those customers.

Q Sure.

A (Witness Evans) Yes. And to add to that, as Mr. Grubb said, I know Walmart has a national account rep that regularly schedules meeting with company experts to make sure we are aware of Walmart's goals and what Walmart's requirements are, whether it be through existing programs or existing facilities to serve or new facilities to serve.

So I feel like we are in very good contact with Walmart, and we are always providing company experts -- making company experts available to have discussions.

Q Sure. And I was really speaking more generally. We work with Walmart in many, many states

across the country. And in regard to -- other different utilities do have stakeholder engagement meetings where a variety of C&I customers, and also residential customers, can get -- provide feedback to potential IRP goals and that sort of thing.

And I just wondered if you would be open to that sort of stakeholder engagement meeting process?

A (Witness Grubb) Again, I think that the conversations that our customer reps are having, they can holistically bring that together and help us incorporate it into the plans.

Q Okay, thank you.

And my last question relates to your direct testimony on page 12 at lines 15 to 22. And there you explain why no action was necessary before filing in this particular docket based on the -- your budget, 2023 load forecast.

A (Witness Grubb) So that's line 21 and 22?

Q It was lines 15 to 22.

A (Witness Grubb) On page 12, yes.

Q Yes.

A (Witness Grubb) One second.

Yes, that's correct. What we are talking about there is even though the load forecast went up between the 2022 IRP and that fall of '22 after the IRP for our

budget '23 forecast, it did not change the year in which we needed to add capacity resources to meet our target reserve margin.

Q Okay. So would Georgia Power plan to act any differently if a similar load trend is revealed in creating its budget 2025 load forecast this August?

A (Witness Grubb) So we have addressed the -- we have identified resources to meet the advance capacity need here. So depending on what comes out of this proposal from a resource standpoint, we will be updating the load forecast every year. And then we will take actions accordingly.

The All-Source RFP is set up well to handle the window, anything needed the end of '28 through '31, but we would just have to adjust it.

But, again, that RFP is going to be able to capture any changes in that capacity projected in those years, and so we will update it every year. In the '25 IRP, we will have an updated load forecast added.

Q So I guess I am getting at, if by August of this year, while you're preparing your budget 2025 load forecast, if you see substantial changes such as changes that you saw that prompted this docket, would you do something differently in terms of notifying the Commission, the parties, that sort of thing, that, Hey,

we are seeing this. We haven't had a chance to update our forecast yet, but we are just giving you warning. We are going to have to make some changes?

A (Witness Grubb) Yes, so a few things there. One, if it increased the need prior to 2028, like we have talked about on the Flex Capacity option, we would address it there. Otherwise, it would be in the other. So it would depend on the magnitude of it, what actions it impacted in the IRP. But if it was a drastic change, we could look at giving folks heads up.

Q Thank you very much. We appreciate the opportunity to speak with all of you and with the Commission. Thank you.

A (Witness Grubb) Thank you.

CHAIRMAN SHAW: Thank you, ma'am.

Redirect?

MR. HEWITSON: Yes, sir.

REDIRECT EXAMINATION

BY MR. HEWITSON:

Q Good afternoon, gentlemen.

A (Witness Evans) Good afternoon.

A (Witness Valle) Good afternoon.

A (Witness Grubb) Good afternoon.

A (Witness Bush) Good afternoon.

Q I guess for the record, but not you, Steve

Hewitson on behalf of Georgia Power Company.

I am going to sort of go backwards in time, if I can, or in reverse order, and start where Mr. McNutt, from the Department of Defense, was asking you some questions.

Now, you looked to existing solar facilities to locate new BESS facilities; is that correct?

A (Witness Grubb) That's correct.

Q Okay. Is it true that you began with the military facilities that have company-owned solar located adjacent to the installation?

A (Witness Grubb) That's correct.

Q Okay. Did you start there because you could work faster at facilities that are not inside the fence line of the base?

A (Witness Grubb) That's correct.

Q Is it true that for the solar facilities located inside the base fence line, federal government processes would take additional time for you to build those resources?

A (Witness Grubb) That's correct.

Q Is the company willing to work with the federal government to expand BESS plus-solar at its facilities?

A (Witness Grubb) Yes.

Q In fact, if the federal government is willing

to pay extra to ensure Georgia Power customers do not pay more, is Georgia Power willing to work with the federal government to explore any option, be it hydro, hydrogen, solar, storage, or even nuclear?

A (Witness Grubb) Yes, we would.

Q Now, Mr. Baker today asked you whether the request in this case included the 500 megawatt of BESS from the 2022 IRP. And I just want to be clear about the request before the Commission in this proceeding, because I think some numbers got jumbled there. The company is asking for 1,000 megawatts of BESS in this IRP update; is that correct?

A (Witness Grubb) That's correct.

Q Mr. Grubb, there has been lots of discussion yesterday and today about whether Georgia Power could or should rely on the intercompany interchange contract for future capacity needs rather than signing a PPA with Mississippi Power Company. Do you remember those questions?

A (Witness Grubb) I do.

Q Why did the company determine it was necessary to sign a PPA with its sister company?

A (Witness Grubb) Because those units would have either been retired or sold off system, and we needed certainty that they would be there to serve our

customers, like they have done today.

Q Now, Mr. Thomas asked several questions regarding the additional sum for the Mississippi Power Company PPA and suggested that the value of the first two years of the PPA does not justify an additional sum. Do you agree with that?

A (Witness Grubb) No, I do not. We had to take all five years to get those resources that are crucial to meeting the earliest needs in this case. And then also, even though we are above target reserve margin, additional megawatts in this first two years do result in a higher reliability on the system.

Q Now, the Commission, of course, oversees the company's IRP planning process every three years; is that right?

A (Witness Grubb) That's correct.

Q How many times has the company come back to the Commission to update the assumption used in the planning process outside of that normal three-year cycle?

A (Witness Grubb) Yeah, this is the first time, and it is because of the extraordinary growth that we have seen in the state since 2022.

Q So under normal circumstances, would you say that the IRP processes overseen by this Commission works pretty well?

A (Witness Grubb) Absolutely.

Q What is the company's track record in terms of reliability, Mr. Grubb?

A (Witness Grubb) So from the aspect of a generation fleet to meet our customers' needs, it is one of the best in the nation.

Q Now, following the 2022 IRP, did the company have sufficient capacity to serve the load that was on the system and under contract at that time?

A (Witness Grubb) Yes. Through the end of 2028, we did.

Q Okay. Now, sitting here today, does the company have sufficient capacity to serve the load that is currently on the system and under contract?

A (Witness Grubb) Yes, we do through the end of 2028.

Q Okay. Now, what changed since the Commission approved the 2022 IRP on July 21st, 2022?

A (Witness Grubb) As we have stated, it is the 40 years of growth that we have seen. And that's 40 years of growth that we have seen in the last two years in terms of customers who have selected Georgia Power as their electrical provider. And then, also, the sustained exponential growth in the customers who want to continue to do business in the state of Georgia.

Q Now, Ms. Whitfield, and some others, have asked you about changing the CARES RFP to procure capacity resources rather than just energy resources. Do you remember those questions?

A (Witness Grubb) I do.

Q Now, to procure a capacity resource, the company needs Commission approval; is that correct?

A (Witness Grubb) That's correct.

Q Is it your understanding that to get that approval, the company must provide an updated load forecast showing the need for that capacity?

A (Witness Grubb) That is correct.

Q Is that exactly what this IRP update is doing, providing an updated load forecast to justify the need for additional capacity?

A (Witness Grubb) It is.

Q Now, there was also a discussion yesterday about the total amount of load the company is planning for. Is the company planning to serve the load of all customers who have the potential to do business within the state of Georgia?

A (Witness Grubb) No. There is more than 17,000 megawatts of potential customers looking at the state of Georgia. What we are planning on is the loads resulting from the 4,000 megawatts that have selected us

as their electrical provider and that exponential growth and the continued number of customers who want to do businesses in Georgia.

Q Okay. Now in simple terms, Mr. Grubb, what is the company planning for in this IRP update?

A (Witness Grubb) So it is -- again, it is the ramp in and the loads from those resources -- those customers who have selected us as electrical provider and the potential growth. And so, we talk about the 17,000. The load forecast is a little below half of that. And half of that load forecast is the load from the resources that we have already got under contract.

Q Now, there were lots of questions yesterday about math and statistics with the suggestion that the company should be planning to serve a lower forecast. If you plan to P50, like Ms. Whitfield suggested by her questions, doesn't that mean there is a 50 percent chance the load will be higher than what you are planning for?

A (Witness Valle) Yes, that is correct. And just to be clear, planning for that level would imply there is a 50 percent chance that we don't have enough resources to meet our load.

Q Now, Mr. Valle, you agreed yesterday that P50 was the most likely result, though, didn't you?

A (Witness Valle) Yes. But from a pure

statistical perspective, that is the theoretical most likely outcome.

Q Okay. Well, why don't you plan for the most likely result then?

A (Witness Valle) We don't plan for a mathematical output. We plan for the most likely load that we have to serve for our customers.

Q Okay. And, Mr. Grubb, as the planner, what happens if you don't have capacity to serve the load when it shows up?

A (Witness Grubb) Yeah. So we jeopardize the reliability that our customers and this Commission expects.

Q Gentlemen, is this forecasting just a math exercise, or are the company's projections based on something more concrete?

A (Witness Grubb) Yeah. No, it is not just a math exercise. As we have mentioned some, it is based on facts. It is tangible projects. It is customer information on potential ramps. And, again, if you look at that 17,000 megawatts, the load forecast is a little under half of that. And about half of that load forecast is customer growth that we have already won and have under contract.

Q Now, you were asked several questions today

regarding the next rate case and certainty about the impacts of this IRP update on that rate case in 2025. Do you remember those questions?

A (Witness Grubb) I do.

Q Okay. Let me ask you this: What would happen if you tabled this request and waited until the 2025 IRP?

A (Witness Grubb) We would not be able to serve the load that we have in the forecast.

Q So the opportunity to provide service to the new economic development load would stall? Is that what you are saying?

A (Witness Grubb) Yes.

Q To address this in a reasonable and prudent manner, have you brought a plan to the Commission that you believe will help make sure that the state does not lose this opportunity?

A (Witness Grubb) Yes, we have.

Q Do you believe your planning includes the necessary and appropriate assumptions on load and revenue forecast to enable Georgia Power to bring to this Commission a risk adjusted plan that is expected to lower costs for all customers?

A (Witness Grubb) Yes, we do.

Q What gives you that confidence, Mr. Grubb?

A Just the fact that we are, again, planning on

less than half of the potential growth that we see in the state and of that load forecast around half of that we've already got in the contract. So that gives us confidence.

MR. HEWITSON: Thank you, gentlemen, for your time.

Mr. Chairman, I would ask that Georgia Power's exhibits be moved into evidence. I believe they are exhibit numbers 1 through 9.

CHAIRMAN SHAW: So marked.

(The documents referred to were admitted into evidence as GPC Exhibits 1 through 9.)

CHAIRMAN SHAW: I've got one final question --

MR. GRUBB: Yes, sir.

CHAIRMAN SHAW: -- to sum it up.

So you've talked a lot about the timing of this request and the filing we've talked in depth about the forecast and so forth. So I just -- you know, Mr. Thomas asked the question about whether or not there might have been enough time after you brought this need to the staff, enough time to conduct an RFP, and you said -- I think you said yes. I just want to make sure that all of -- that y'all looked at all of the options, you know, choosing to self-build and not do RFPs. I just want to make

sure you haven't hand-picked these projects.

So what would your answer be in -- I'm asking you, have y'all looked at all of the options before you brought this to us?

MR. GRUBB: So as we've mentioned, we did have to move quickly and identify resources. So we started the system link because we knew there's two challenges: Building anything and transmission. We looked at the system link and reached out to several marketing -- market resources that we knew and evaluated a few of those, so that's what we got.

After that, there were no other existing resources that we were aware of that wouldn't require an RFP and transmission construction. And so then we looked at the types of generation we can deploy the quickest, and in sites that we knew from a transmission standpoint we can move quickly on.

So have we looked at every single option? I don't know every single option that's out there, but what we have done is brought forth an efficient and reliable and flexible resource plan that's backed up by our modeling that shows through '28 purchase power batteries and CTs are an optimal solution for customers.

CHAIRMAN SHAW: Thank you.

Commissioners, do we have -- anyone else have anything else to add before we finish up?

COMMISSIONER PRIDEMORE: If there was a change to the State's tax credit policy, would that change the load that is expected? Would it change what was needed to generate electricity?

MR. GRUBB: So when you -- just to be clear, when you say a tax change, you mean in terms of an increase, decrease, on resources? I just want to make sure I'm -- we're understanding the question.

CHAIRMAN SHAW: You're talking about a tax credit on data centers --

COMMISSIONER PRIDEMORE: If data center tax credits were removed, how would that impact this modeling?

MR. VALLE: That would be to be determined. So we don't factor in specifically a model specifically tax benefits into the load. We see what the load comes to, to our territory, and then that we plan on serving. So to the extent that the load may change, we would update it, but there's nothing that is explicitly model.

MR. GRUBB: And, again, Commissioners, I would mention there's 17 to 20,000 megawatts looking -- I don't know how many of those would change their

approach from tax credit, but it's a -- there's a lot more that's looking at the state than what we planned for.

MR. EVANS: That's right. And as we said yesterday, there's many factors that bring customers here: Our infrastructure, our fiber, our reliability, our pricing, things like that that are here and won't change. So tax credits are one of them, but there's many things that bring customers here.

COMMISSIONER SHAW: Okay. Is there any other housekeeping matters to take up?

MS. WHITFIELD: Mr. Chair, I believe I forgot to move GIPL's Exhibits 1 through 3 into evidence, and if I could do that now, I would like the opportunity.

COMMISSIONER SHAW: So marked.

MS. WHITFIELD: Thank you.

(The documents referred to were admitted into evidence as GIPL's Exhibits 1 through 3.)

COMMISSIONER MCDONALD: Mr. Chairman, let's keep our thoughts and prayers to our linemen and women in this bad weather, whether it's Georgia Power or EMC, or what, but they're under dire conditions out there.

MR. GRUBB: And they did a great job of making sure we got through today.

CHAIRMAN SHAW: Yes, they did. The lights didn't even blink.

All right. I'll ask the court reporter at this time to make all exhibits part of the record. Thank y'all for your time. Be safe going home. This hearing is now concluded and we are adjourned.

(Hearing adjourned at 3:28 p.m.)

C E R T I F I C A T E

We, Kelley Marie Nadotti, Debbie A. Eickhoff, and Brenda P. Elwell, Certified Court Reporters, do hereby certify that the foregoing transcript is an accurate record of the proceedings had in the above-entitled matter at the time and place therein set forth.



Kelley Marie Nadotti, RPR, CCR
6256-8388-8026-4192



Brenda P. Elwell, RPR, CCR, B-2023



Debbie A. Eickhoff, RPR, CCR
5090-9084-2699-3664

GPC Exhibit 2

PUBLIC DISCLOSURE

Docket No. 55378

Georgia Power

2023 Integrated Resource Plan Update

Technical Appendix

October 2023

BEFORE THE GEORGIA PUBLIC SERVICE COMMISSION

GEORGIA POWER COMPANY
DOCKET NO. 55378

AFFIDAVIT AND BASIS FOR THE ASSERTION THAT PORTIONS OF THE INFORMATION SUBMITTED ARE PROTECTED TRADE SECRETS

As part of its 2023 Integrated Resource Plan Update ("2023 IRP Update"), filed in Docket No. 55378, Georgia Power Company ("Georgia Power" or the "Company") submits to the Georgia Public Service Commission a Technical Appendix, which contains power purchase agreements and data supporting proposed projects including an acquisition and Company-owned proposals, which include sensitive pricing, resource operational capability data, and development timelines, and also certain information regarding the Company's proprietary planning processes, financial data, technology screening assumptions, generic technology and resource cost information, specific resource, technology and avoided cost information, economic analyses, load and energy forecast data assumptions, and other data, including confidential details regarding current and future transmission projects (the "Information"). Certain portions of the Information are trade secrets of Georgia Power and Southern Company and their affiliates and is therefore protected from public disclosure under Commission Rule 515-3-1-.11.

The trade secret portions of the Information derive economic value from not being generally known to, and not being readily ascertainable by proper means by other persons who can obtain economic value from their disclosure or use. Specifically, the trade secret portions of the Information contained herein include competitively sensitive pricing and operational capability data, including project development timelines where applicable, specific to the resources under contract within each power purchase agreement or proposed to be acquired or developed. If the Information were made public, competitors, bidders, and suppliers could use the Information to unfairly manipulate the request for proposals process and competitive market to structure future bids and set an artificial price floor to arbitrarily increase prices to the detriment of the Company and its customers. Public dissemination of the Information would undermine Georgia Power's ability to negotiate the best price and contract terms and could harm the Company's ability to secure the best cost bids and resources for the benefit of customers. In addition, the terms of the power purchase agreements themselves provides for the confidentiality and protection of the Information. Compromising the confidentiality of such Information could harm Georgia Power in future PPA negotiations, as counterparties may fear compelled disclosure of key contractual terms. Lastly, the Company's competitors are not required to reveal or publish similar information.

The trade secret portions of the Information also contain competitively sensitive cost information related to available technology options, processes and data used by Georgia Power in analyzing resource addition schedules, financial data used in the Company's resource analyses, and other confidential details including data supporting resource economic evaluations. Public dissemination of the trade secret portions of the Information would allow Georgia Power's competitors and suppliers to have access to such processes and strategies and thereby gain an unfair competitive advantage in the marketplace. Competitors would obtain an unfair advantage because they are not required to reveal similar information and can utilize such trade secret portions of the Information to manipulate pricing and timing of supply to the disadvantage of Georgia Power. Competitors would also unfairly benefit in having access and insight into the Company's planning processes and methodologies. This competitive advantage for the Company's suppliers and competitors would mean that Georgia Power will potentially pay higher prices to suppliers, ultimately harming Georgia Power and its customers.

Certain trade secret portions of the Information provided include load and energy forecast data assumptions such as projections of new customer load the Company assesses it may be selected to serve in the near future, estimates of parameter inputs for modeling probability distributions, and the values of any external adjustments made to the forecast. Public disclosure of the Information could unfairly alter the Company's negotiation position with prospective new customers, which could result in a less advantageous rate being secured and thus potentially harming retail customers through higher rates. In addition, the Company's competitors are not required to file their respective competitive intelligence information.

Additionally, the Information contains competitively sensitive cost information related to the prices Georgia Power has estimated for transmission equipment and specific details related to the Company's transmission infrastructure. Public dissemination of the Information would allow Georgia Power's competitors and suppliers to have access to the costs paid by the Company and insight into the Company's transmission planning process. Access to the Information would also allow competitors to gain specific insight into the Company's technical analysis regarding planned projects. Competitors would obtain an unfair advantage because they are not required to reveal similar information and can structure the pricing for competing products based on the Information. In the event the Information was released, it is quite likely that suppliers would use the Information to set the floor in establishing their own prices, thus artificially and inefficiently setting a market price that may not be representative of the best cost that the market could offer. Competitors would also unfairly benefit in having access and insight into the Company's planning processes and methodologies. This competitive advantage for the Company's suppliers and competitors would mean that Georgia Power will potentially pay higher prices to suppliers, ultimately harming Georgia Power.

The trade secret portions of the Information are subject to substantial procedures to maintain their secrecy. Only select Georgia Power and Southern Company personnel are granted access to the trade secret portions of the Information. Those personnel receive access only on a "need to know" basis. Parties outside Georgia Power and Southern Company affiliates and their legal counsel who have been granted access to the trade secret portions of the Information, if any, have been required to sign confidentiality agreements.

Jeffrey R. Grubb, first being duly sworn, deposes and states that he has reviewed the Technical Appendix of the Company's 2023 IRP Update and that to the best of his knowledge the specific information designated as trade secret constitute trade secrets in accordance with O.C.G.A. § 10-1-761 (2021).

Jeffrey R. Grubb
Director, Resource Policy & Planning
Georgia Power Company

Subscribed and sworn to before me this 23rd day of October, 2023.

Notary Public

My Commission expires:

4/26/26



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Technical Appendix Contents

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2. Power Purchase Agreement Between Georgia Power Company and Santa Rosa Energy Center LLC

3. Technical Information Supporting the Potential Acquisition of an Additional Ownership Interest in an Existing Generating Asset

4. Technical Information Supporting the Proposal to Develop 178 MW of Battery Energy Storage Systems at Robins and Moody Air Force Bases

5. Technical Information Supporting the Proposal to Develop 200 MW of Battery Energy Storage Systems Co-located with 200 MW of New Solar

6. Technical Information Supporting the Proposal to Develop up to 1,400 MW from Three Simple Cycle Combustion Turbines at Plant Yates

7. Load and Energy Forecast

8. Resource Mix Study

9. Economic Analysis of Capacity Resources

10. Transmission Screening Analyses

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Execution Version

POWER SUPPLY AGREEMENT

BY AND BETWEEN

MISSISSIPPI POWER COMPANY

AND

GEORGIA POWER COMPANY

Dated as of October 11, 2023

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POWER SUPPLY SERVICE SCHEDULE

Execution Version

POWER SUPPLY AGREEMENT
BY AND BETWEEN
MISSISSIPPI POWER COMPANY
AND
GEORGIA POWER COMPANY

This Power Supply Agreement ("Agreement") is entered into and effective this 11th day of October, 2023 ("Effective Date"), by and between **MISSISSIPPI POWER COMPANY** (by and through its agent, Southern Company Services, Inc.), a corporation organized and existing under the laws of the State of Mississippi ("**MPC**" or "**Seller**"), and **GEORGIA POWER COMPANY** ("**GPC**"), a corporation organized under the laws of the State of Georgia (referred to herein as "**Buyer**"). Seller and Buyer may be individually referred to as a "Party" and collectively as the "Parties".

W I T N E S S E T H:

WHEREAS, Seller is an electric utility operating company engaged in, among other things, the sale of electric power at wholesale and has received authorization from the Federal Energy Regulatory Commission to provide wholesale power supply services at market-based rates in accordance with the Tariff (as hereinafter defined); and

WHEREAS, Buyer is an electric utility operating company which, among other things, provides retail electric service to end-use customers in its franchise service territory in the State of Georgia and is authorized to purchase wholesale power supply services; and

WHEREAS, subject to the terms and condition of this Agreement, the Parties desire for Seller to supply capacity and associated energy to Buyer and for Buyer to purchase capacity and associated energy from Seller pursuant to this Agreement the principal purpose is to supply Buyer's retail electric customers; provided, however, that if this Agreement is not approved

through a Commission Certificate as provided in Section 9.4, then in such case Buyer agrees to utilize the capacity and energy supplied hereunder for the purpose of exclusively supplying Buyer's wholesale electric customers and not its retail electric customers.

NOW, THEREFORE, in consideration of the premises and of the mutual covenants herein set forth, and other good and valuable consideration, the receipt, sufficiency and adequacy of which are hereby acknowledged, Seller and Buyer, each intending to be legally bound, hereby agree as follows:

ARTICLE 1

DEFINITIONS AND INTERPRETATION

1.1 Definitions. All capitalized terms used herein and not otherwise defined, whether singular or plural, shall have the respective meanings set forth below:

"**Affiliate**" means, for any specified corporation, any other entity directly or indirectly controlling or controlled by or under direct or indirect common control with such specified corporation. For purposes of this definition, "control" when used with respect to any entity shall mean the power to direct the management and policies of such entity, directly or indirectly, whether through the ownership of voting securities, by contract or otherwise; and the terms "controlling" and "controlled" have meanings correlative to the foregoing.

"**Agreement**" means, as set forth in the preamble, this Power Supply Agreement, as may be amended from time to time.

"**Arbitration Expenses**" has the meaning set forth in Section 14.5.4.

"**Arbitration Initiation Date**" has the meaning set forth in Section 14.5.

"**Arbitration Notice**" has the meaning set forth in Section 14.5.

"**Assignee**" has the meaning set forth in Section 17.1.2.

"**Assignment Conditions**" has the meaning set forth in Section 17.1.2.

"**Business Day**" means any Day other than a Saturday, Sunday or any Day that has been established as a NERC defined holiday.

"**Business Hour**" has the meaning set forth in Section 17.7.

"**Buyer**" means, as set forth in the preamble, Georgia Power Company, and its permitted successors and assigns.

"**Central Prevailing Time**" or "**CPT**" means the local time on a given Day in Birmingham, Alabama.

"**Confidential Information**" has the meaning set forth in Section 16.1.

"**CPR**" means the International Institute for Conflict Prevention & Resolution.

"**Day**" means a calendar day, commencing at one (1) minute prior to 12:01 a.m. CPT of each such calendar day and ending at one (1) minute after 11:59 p.m. CPT of such calendar day in Birmingham, Alabama.

"**Defaulting Party**" has the meaning set forth in Section 13.1.

"**Dispute Impasse Notice**" has the meaning set forth in Section 14.3.

"**Dispute Response**" has the meaning set forth in Section 14.2.

"**Disputed Amount**" has the meaning set forth in Section 7.2.1.

"**Disputing Party**" has the meaning set forth in Section 14.2.

"**Early Termination Notice**" has the meaning set forth in Section 2.4.3.

"**Early Termination Notice Deadline**" has the meaning set forth in Section 2.4.3.

"**Effective Date**" has the meaning set forth in the preamble to this Agreement.

"**Event of Default**" has the meaning set forth in Section 13.1.

"**Federal Arbitration Act**" means the United States Arbitration Act, 9 U.S.C.A. § 1 *et seq.*, as the same may hereafter be amended from time to time.

"**Federal Power Act**" means the Federal Power Act, 16 U.S.C.A. §§ 791a-828c, as the same may hereafter be amended from time to time.

"**FERC**" means the Federal Energy Regulatory Commission or any Governmental Authority succeeding to the powers and functions thereof under the Federal Power Act.

"**Firm and Native Load**" shall mean the demands of wholesale and retail power customers for which the Seller, by statute, franchise, regulatory requirements, or contract, has undertaken the obligation to plan, construct and operate its system to provide reliable power supply services and meet the electric needs of such customers. For purposes of this Agreement, Firm and Native Load shall be defined as interruptible for reliability reasons only and shall not include loads associated with interruptible, curtailable, and other demand-side management programs.

"**Governmental Authority**" means any local, state, regional or federal administrative, legal, judicial, or executive agency, commission, department, or other such entity.

"**GPSC**" means the Georgia Public Service Commission.

"**Hour**" means one (1) of the twenty-four (24) clock-hours of a Day.

"**Hourly**" has a meaning correlative to that of Hour.

"**IIC**" means that certain Southern Company System Intercompany Interchange Contract, as filed pursuant to 119 FERC ¶ 61,065 (2007) and designated as Southern Company Services, Inc., Second Revised Rate Schedule FERC No. 138, by and among Seller and certain of its Affiliates, including the IIC Manual, and excluding periodic informational filings, as the same may

be amended and restated, or any successor contract filed with FERC among Seller and certain of its Affiliates for coordinated operations.

"**IIC Manual**" means the Allocation Methodology and Periodic Rate Computation Manual attached to, and incorporated in, the IIC as the same may be amended and restated from time to time, or any successor document serving the same purpose made a part of the IIC and filed with FERC, excluding periodic informational filings.

"**Interest Rate**" means the rate per annum equal to the lesser of: (i) the highest interest rate allowed by Law; or (ii) two percent (2%) plus the prime rate, as stated in the *Wall Street Journal* on the date payment is due.

"**kW**" means kilowatts.

"**Law**" means, whether in effect as of the Effective Date or at any time in the future, any act; statute; law; requirement; ordinance; order; ruling or rule; regulation; standards and/or criteria contained in any permit, license, or other approval; legislative or administrative action by any Governmental Authority; or a decree, judgment or order of any Governmental Authority.

"**Mediation Election**" has the meaning set forth in Section 14.4.

"**Month**" means a calendar month.

"**Monthly**" has a meaning correlative to that of Month.

"**Monthly Capacity Payment**" has the meaning set forth in Section 5.1 of the Service Schedule.

"**Monthly Energy Payment**" has the meaning set forth in Section 5.2 of the Service Schedule.

"**MPSC**" means the Mississippi Public Service Commission.

"**MW**" means megawatts.

"**MWh**" means megawatt hours.

"**NERC**" means the North American Electric Reliability Corporation (and any successor thereto).

"**Non-Defaulting Party**" has the meaning set forth in Section 13.1.

"**Notice of Dispute**" has the meaning set forth in Section 14.2.

"**Operating Committee**" has the meaning set forth in Section 4.2.1.

"**Operating Representatives**" has the meaning set forth in Section 4.2.1.

"**Party**" or "**Parties**" has the meaning given such terms in the preamble of this Agreement.

"**Person**" means any natural person, corporation, limited liability company, general partnership, limited partnership, proprietorship, other business organization, trust, union, association, or Governmental Authority.

"**Point(s) of Receipt**" means with respect to the various generating units on the Southern Electric System that are providing capacity and energy under this Agreement, the high voltage side of the generation step-up transformers of such units.

"**Principals**" means (i) with respect to Buyer, Buyer's Vice President of Pricing and Planning or Chief Executive Officer, and (ii) with respect to Seller, Seller's Chief Production Officer, Chief Executive Officer, or the Vice President of the Southern Wholesale Energy business unit.

"**Responding Party**" has the meaning set forth in Section 14.2.

"**SCS**" means Southern Company Services, Inc., an Alabama corporation.

"**SEC**" has the meaning set forth in Section 16.2.3.

"**Seller**" means, as set forth in the preamble, Mississippi Power Company, by and through its wholesale services agent, Southern Wholesale Energy, a business unit of Southern Company Services, Inc., and its permitted successors and assigns.

"**Senior Officer**" means an individual, employed as a senior officer of a Party, designated by such Party as its representative in matters that are subject to Section 14.3 of this Agreement.

"**Service Schedule**" means the Power Supply Service Schedule, which is attached to this Agreement and incorporated into this Agreement by reference.

"**Service Term**" has the meaning set forth in Section 2.1.

"**Southern Company**" means The Southern Company, a Delaware corporation, or its successor(s).

"**Southern Electric System**" means the high voltage electric system on which transmission service is provided pursuant to the Southern OATT, as such system may be modified or expanded from time to time, as well as any successor in function.

"**Southern OATT**" means the Open Access Transmission Tariff of those Southern Operating Companies that own or control transmission facilities, or a successor tariff governing transmission on the Southern Electric System that has been accepted by FERC, as such tariffs may be changed or amended from time to time.

"**Southern Operating Companies**" means, collectively, the electric utility operating company Affiliates of Southern Company engaged in common dispatch and control of generating resources, currently including Alabama Power Company, Georgia Power Company, Mississippi Power Company, and Southern Power Company.

"**Standard Arbitration Process**" means the process set forth in Section 14.5.1.

"**Streamlined Arbitration Process**" means the process set forth in Section 14.5.2.

"**Submission**" means a precise statement of the issue(s) in dispute, a proposed resolution of the issue(s) in dispute, including a monetary amount and the supporting calculations if applicable, and the factual and/or legal support therefor; provided that any such monetary amount will be limited to the damages allowed pursuant to the Agreement.

"**Tariff**" means Southern Operating Companies' Market Based Rate Tariff, Southern's Tariff Volume No. 4, as superseded or amended from time to time.

"**Taxes**" means any or all ad valorem, property, occupational, severance, emissions, generation, conservation, transmission, utility, gross receipts, privilege, sales, transfer, use, excise and other taxes, fees, assessments, licenses, and any other charges imposed by a Governmental Authority, but excluding taxes based on net income or net worth.

"**Term**" has the meaning set forth in Section 2.1.

"**Year**" means a calendar year.

1.2 Interpretation. In this Agreement, unless the context otherwise requires, the singular shall include the plural and any pronoun shall include the corresponding masculine, feminine and neuter forms. The words "hereof," "herein," "hereto" and "hereunder" and words of similar import when used in this Agreement shall, unless otherwise expressly specified, refer to this Agreement as a whole and not to any particular provision of this Agreement. Whenever the term "including" is used herein in connection with a listing of items included within a prior reference, such listing shall be interpreted to be illustrative only, and shall not be interpreted as a limitation on or exclusive listing of the items included within the prior reference. Any reference in this Agreement to "Section," "Article," "Appendix", or "Service Schedule" shall be references

to this Agreement unless otherwise stated, and all such Appendices, and the Service Schedule shall be incorporated in this Agreement by reference. In the event that any index or publication referenced in this Agreement ceases to be published, each such reference shall be deemed a reference to a successor or alternate index or publication reasonably agreed to by the Parties. Unless specified otherwise, a reference to a given agreement or instrument, and all schedules, exhibits, appendices and attachments thereto, shall be a reference to that agreement or instrument as modified, amended, supplemented, and restated, and in effect from time to time. Unless otherwise stated, any reference in this Agreement to any entity shall include its permitted successors and assigns, and in the case of any Governmental Authority, any Person succeeding to its functions and capacities.

1.3 Construction. Each Party acknowledge that it was actively involved in the negotiation and drafting of this Agreement and that no law or rule of construction shall be raised or used in which the provisions of this Agreement shall be construed in favor of or against either Party because one is deemed to be the author thereof.

ARTICLE 2

TERM OF THE AGREEMENT

2.1 Term. The "Term" of this Agreement shall be the period beginning on the Effective Date and continuing inclusive through one (1) minute after 11:59 p.m. Central Prevailing Time on the Day on which the Service Term expires (as determined below), unless this Agreement is terminated earlier pursuant to other applicable provisions of this Agreement. Subject to the earlier

termination of this Agreement pursuant to the provisions hereof, the "Service Term" shall be the period of time, commencing on January 1, 2024, and continuing through December 31, 2028.

2.2 Survival . All provisions of this Agreement that expressly come into or continue in force and effect following the termination or expiration of this Agreement shall remain in effect and be enforceable following such expiration or termination. In addition, the following provisions of this Agreement which by virtue of their purpose should continue in force and effect following the termination or expiration of this Agreement shall remain in effect and be enforceable following such expiration or termination until such purpose has been fulfilled: Article 6, Article 7, Article 9, Article 12, Section 13.2, Section 13.3, Article 14, Article 16 and Article 17, and any additional provisions hereof necessary to implement or interpret the foregoing.

ARTICLE 3

[RESERVED]

ARTICLE 4

SALE AND PURCHASE OF POWER SUPPLY;

OPERATING COMMITTEE

4.1 Sale and Purchase of Power Supply. Seller agrees to deliver and sell, and Buyer agrees to receive and purchase, electric power supply pursuant to the Service Schedule and the terms and conditions of this Agreement. All energy delivered by Seller shall meet applicable power quality standards of NERC and the Southern OATT. Such energy and capacity shall principally be used to supply Buyer's retail electric customers; provided, however, that if this Agreement is not approved through a Commission Certificate as provided in Section 9.4, then in

such event, Buyer agrees to utilize the capacity and energy supplied hereunder for the purpose of exclusively supplying Buyer's wholesale electric customers and not its retail electric customers.

4.2 Operating Committee.

4.2.1 Buyer and Seller shall each designate one representative and one alternate ("Operating Representatives") who shall act for the respective Parties in matters pertaining to detailed operating arrangements for service hereunder. The Operating Representatives, or their alternates, shall comprise and be referred to as the "Operating Committee".

4.2.2 The Operating Committee shall have responsibility for the following:

(a) Establishment of arrangements such as metering, telemetering, telecommunications and data acquisition associated with the delivery and receipt of energy hereunder to the extent not provided for by this Agreement or the applicable transmission service arrangements.

(b) Communications regarding methods and procedures for accounting and billing hereunder.

(c) Establishment of day-to-day operating procedures.

(d) Such other duties as may be conferred upon it by mutual agreement of Buyer and Seller.

Both Buyer and Seller shall cooperate in providing to the Operating Committee all information required in the performance of its duties. If the Operating Committee is unable to agree on any matter falling under its jurisdiction, such matter shall be referred by the Operating Representatives to their Principals for a decision. Failure of the Principals to agree on any matter referred to them shall not constitute a basis for termination of this

Agreement, provided, however, that any such unresolved matter may be subject to further process in accordance with the terms of Article 14 of this Agreement. All decisions or agreements made by the Operating Committee shall be evidenced in writing.

4.2.3 Unless otherwise agreed, the Operating Committee shall hold an annual meeting at a mutually convenient time and place to review the duties set forth herein. The first such meeting shall take place no later than December 1, 2023, to permit adequate time for implementation. When requested by either Buyer or Seller, the Operating Committee shall also meet at the earliest opportunity for consideration of matters under its jurisdiction.

4.2.4 In no event shall any operating procedures under this Agreement modify (or be construed as modifying) any of the terms or conditions of this Agreement. In the event of a conflict or inconsistency between this Agreement and any operating procedures, the terms of this Agreement shall govern to the extent of the conflict or inconsistency.

ARTICLE 5

TRANSMISSION SERVICE

5.1 Buyer Obligations.

5.1.1 Buyer shall have the sole and exclusive responsibility at all times to make arrangements for, obtain, contract and pay for any and all transmission service and ancillary services required (including service under any applicable transmission tariff) in order to receive energy provided under this Agreement at the Point(s) of Receipt and in order to deliver such energy beyond the Point(s) of Receipt on the Southern Electric System to transmit or deliver energy provided hereunder. Buyer assumes the risk associated with the availability, adequacy and cost of such transmission service and ancillary services. In the

event that Buyer is unable to obtain or maintain such transmission service for any period during the Service Term of this Agreement for any reason, except as otherwise provided in this Agreement, Buyer shall not be relieved of the obligation to pay Seller the Monthly Capacity Payments and Monthly Energy Payments applicable to such period, each as calculated under the Service Schedule.

5.1.2 Buyer shall be responsible for complying with any scheduling and tagging requirements associated with energy provided hereunder.

5.2 Seller Obligations. Seller, or its designee, shall have the sole and exclusive responsibility at all times to make arrangements for, obtain, contract and pay for any and all transmission service and ancillary services required (including any service under any applicable transmission tariff) to deliver energy provided under this Agreement to the Point(s) of Receipt. Seller assumes all risk associated with the availability, adequacy and cost of such transmission service and ancillary services.

5.3 Regional Transmission Organizations. In the event that a Regional Transmission Organization(s) or similar organization is formed to which one or both of the Parties becomes a participant and such participation in that organization has, or is reasonably expected to (i) have a material adverse effect upon a Party's ability to perform its obligations under, or to realize the material, direct economic benefits of this Agreement, including but not limited to material changes in the scheduling requirements, costs associated with the delivery of energy to and/or from the Point(s) of Receipt, and/or costs associated with or resulting from any auction or other market structure or design, or (ii) render the performance of a Party's obligations under this Agreement illegal or unenforceable, then the Parties shall negotiate an amendment of this Agreement in good

faith to reallocate the responsibilities to reflect the benefits and burdens of this Agreement as of the date of this Agreement consistent with the Parties intentions. If the Parties fail to agree on such an amendment, then the Party affected by such changes may terminate this Agreement upon no less than one-hundred twenty (120) days prior written notice to the other Party.

ARTICLE 6

PAYMENTS

6.1 Monthly Capacity Payments. For each Month of the Service Term, Buyer shall pay to Seller the Monthly Capacity Payment, as determined pursuant to Section 5.1 of the Service Schedule.

6.2 Monthly Energy Payments. For each Month of the Service Term, Buyer shall pay to Seller the Monthly Energy Payment, as determined pursuant to Section 5.2 of the Service Schedule.

6.3 Additional Payments. In addition to the payments specified in this Article 6, each Party shall pay to the other Party all other amounts due pursuant to the other provisions of this Agreement.

6.4 Netting of Payments The Parties hereby agree that, to the extent applicable, they shall discharge mutual debts and payment obligations due and owing to each other pursuant to this Agreement through netting, in which case all amounts owed by each Party pursuant to this Agreement, including any related damages, interest, and payments or credits, shall be shown on the Monthly invoice prepared pursuant to Section 7.1, if applicable, and netted so that only the net amount remaining due shall be paid by the Party who owes it.

ARTICLE 7

BILLING AND PAYMENT

7.1 Billing and Payment.

7.1.1 As promptly as practicable after the end of each Month during the Service Term, Seller shall send Buyer an invoice stating the payments and any other amounts required to be paid by Buyer to Seller, including the following adjustments from prior Monthly invoices (if applicable): (a) any billing true-ups or corrections, including charges or credits, identified by either Party subsequent to the last Monthly invoice, which shall not be subject to interest; (b) any billing corrections, including charges or credits, that the Parties have mutually agreed upon or otherwise resolved in accordance with Section 7.2 subsequent to the last Monthly invoice, which shall be subject to interest in accordance with Section 7.2; (c) any billing corrections, including charges or credits, that have been resolved pursuant to Article 14 subsequent to the last Monthly invoice, which shall be subject to interest in accordance with Section 7.2; and (d) any overdue amounts, excluding properly withheld Disputed Amounts, which shall be subject to interest in accordance with Section 7.2.

7.1.2 Each such Monthly payment shall be due and payable on or before the tenth (10th) Day after Buyer's receipt of such invoice. If such tenth (10th) Day after Buyer's receipt is not a Business Day, then payment shall be due on the next succeeding Business Day. Buyer shall make payment to Seller in accordance with such invoices on or before the date due in immediately available funds through wire transfer of funds or other means acceptable to Seller. If Buyer does not make a payment on or before such tenth (10th) Day,

then interest shall be added to the overdue payment, from the date such overdue payment was due until such overdue payment together with interest is paid, which interest shall be compounded Monthly at the Interest Rate.

7.2 Billing Disputes and Final Accounting.

7.2.1 If Buyer questions or contests the correctness of any invoiced amount, whether a charge or a credit, of any payment claimed to be due pursuant to this Agreement, then Buyer shall provide written notice to Seller which (i) states the good faith basis for the dispute, (ii) specifies the portion of the invoiced amount in dispute (the "Disputed Amount"), if any, and (iii) provides documentation reasonably supporting the determination of the Disputed Amount.

7.2.2 Buyer shall make payment to Seller of the Disputed Amount under protest and, if Buyer is thereafter determined to be entitled to reimbursement, Buyer shall be reimbursed by Seller for any amount in error after the settlement of such question or contest, in accordance with this Section 7.2.

7.2.3 In the event that Buyer, by timely notice to Seller in accordance with Section 7.2.1, questions or contests the correctness of any charge or credit, Seller shall review within a reasonable time frame the questioned charge or credit and shall notify Buyer of the amount of any error and the amount of any payment or reimbursement that Buyer is required to make or is entitled to receive in respect of such alleged error. Reimbursements determined to be due from Seller under this Section 7.2.3 shall be included on the next Monthly invoice with interest, calculated from the date such payment was made by Buyer. Interest shall be compounded Monthly at the Interest Rate.

7.2.4 Buyer shall have until one (1) year after receipt of an invoice to question or contest the correctness of any charge or credit set forth in such invoice pursuant to Section 7.1 or 7.2. If no question or contest is raised during such time period, the correctness of all such charges and credits shall be conclusively presumed.

7.3 Availability of Records. At any time prior to the end of the one (1) year period set forth in Section 7.2.4, Seller and Buyer, or any third party representative of such Party reasonably acceptable to the other Party, shall have the right upon reasonable notice, at such Party's sole expense and during normal working hours, to examine original records or copies of the records, as appropriate, of the other Party to the extent reasonably necessary to verify the accuracy of any Monthly invoice, charge or computation made pursuant to this Agreement. Each Party shall keep such records as may be reasonably necessary to afford a clear and complete history of the transactions hereunder for such one (1) year period or, in the event that a Party questions or contests the correctness of any charge or credit, until such question or contest is finally resolved; provided that, if a Party initiates an audit through a written notice to the other Party within the time period the records and documents relating to such audit are required to be maintained under this Section 7.3, then the other Party will retain such records and documents for at least two (2) years after receipt of such notice. If an audit is requested by either Party with respect to such records and those records cannot be disclosed to such requesting Party as a result of a confidentiality obligation, then to the extent legally permissible, the Parties shall select an independent auditor to perform the audit consistent with the Parties' rights under this Agreement and with such confidentiality arrangements as may be required by the confidentiality obligation in question. No payment made pursuant to the provisions of this Article 7 shall constitute a waiver of any right of Buyer under

Section 7.2 to question or contest the correctness of any charge or credit by Seller or to dispute Seller's resolution of any such question or contest. The Party requesting the audit shall pay all of its own costs associated with the audit, including those of any independent auditor associated with the audit.

ARTICLE 8

[RESERVED]

ARTICLE 9

REGULATORY

9.1 Service Rendered. This Agreement is intended as a service agreement pursuant to the Tariff. Seller shall provide and Buyer shall receive and pay for power supplied under this Agreement pursuant to the terms and conditions of the Tariff and of this Agreement. To the extent the terms and conditions of the Tariff are inconsistent with those set forth in this Agreement, the provisions of this Agreement shall control.

9.2 Market Rate Tariff.

9.2.1 It is the expressed intent of the Parties that this Agreement be a sale pursuant to the Tariff without any modifications of this Agreement's charges, terms and conditions and without additional filing requirements. If, at any time as a result of such proceedings (or any other proceeding), FERC does not allow this Agreement to function pursuant to the Tariff or requires any cost of service support for any charges hereunder, Buyer agrees to take reasonable steps, as requested by Seller, to cooperate with and assist Seller in securing acceptance by the FERC of all charges and terms as stated in this Agreement. If, at any

time as a result of such proceedings (or any other proceeding), FERC orders any changes to any charges or terms hereunder or any refunds, including interest or penalties, Buyer agrees that Seller shall have the right to file one or more unilateral changes to the charges and terms hereunder to recover the revenues, as closely as practicable, intended by this Agreement in its original form. Seller agrees that Buyer shall not be precluded from participating in any related FERC proceeding, pursuant to applicable FERC procedures and consistent with this Section 9.2

9.2.2 Buyer agrees to take reasonable steps, including filing a motion to intervene and supporting comments, as requested by Seller in securing acceptance by the FERC of any and all such changes, in as expeditious a manner as is practicable, to the extent such changes, in Buyer's sole discretion, do not result in: (i) higher aggregate charges to Buyer than the aggregate charges intended by this Agreement in its original form, or (ii) changes in the terms and conditions of service intended by this Agreement in its original form which are materially adverse to Buyer.

9.2.3 Seller and Buyer each agree that, except as expressly permitted under Section 9.2.1, it shall not seek to modify this Agreement under Sections 205 or 206 of the Federal Power Act or any other provision of Law, and will take reasonable steps (including the submission or support of filings) to oppose any such modification, except to the extent such modification is agreed by the Parties.

9.2.4 The Parties agree and intend that, with respect to any change to a term or condition under this Agreement that is proposed or sought by a third party or FERC (acting *sua sponte*), the standard of review shall be the "public interest" standard of review set

forth in United Gas Pipe Line Co. v. Mobile Gas Service Corp., 350 U.S. 332 (1956) and Federal Power Commission v. Sierra Pacific Power Co., 350 U.S. 348 (1956).

9.3 Character of Transactions. The sale by Seller to Buyer of capacity and energy under this Agreement shall not constitute either: (i) a sale, lease, transfer or conveyance of an ownership interest or contractual right in or to any specific generation facility or resource; or (ii) a dedication of ownership or an entitlement to the capacity or output of any specific generation facility or resource. Furthermore, Buyer acknowledges and agrees that Seller, or its agent, shall have the sole authority, which Seller or its agent may exercise in its sole discretion, to manage, control, operate and maintain the generating resources used to supply Buyer under this Agreement. Seller may serve Buyer with energy under this Agreement from any resource available to Seller, in Seller's sole and absolute discretion.

9.4 Regulatory Condition. (a) Buyer will use reasonable efforts to obtain a certificate from the Georgia Public Service Commission (the "**Commission**" and such granted certificate the "**Commission Certificate**") approving this Agreement without material qualifications or conditions that adversely affect the Buyer or Seller, and in furtherance thereof, to target a filing of the application as soon as reasonably practicable after execution of this Agreement. Seller agrees to assist and support the Buyer in a timely manner and to the extent reasonably requested by Buyer in obtaining the Commission Certificate.

(b) If: (i) the Commission issues a Commission Certificate that is subject to material qualifications or conditions that adversely affect Buyer or Seller; (ii) the Commission has not approved this Agreement through the granting of a Commission Certificate for the recovery in retail rates; or (iii) the Commission fails to issue a Commission Certificate by the date required in

Commission Rule 515-3-4-.07(1)(e)(5) or by a later date that is otherwise acceptable to Buyer, but no later than 180 days after that first date, then Buyer agrees to utilize the capacity and energy supplied under this Agreement, without modification, for the purpose of exclusively serving its wholesale electric customers and not its retail electric customers; provided, that with respect to subsection (b)(i) above, Buyer will have the option to continue to use the capacity and energy supplied hereunder if Buyer assumes the cost and risk associated with such material qualifications and conditions established in such amended Commission Certificate subject to the agreement of Seller if Seller would be adversely affected.

(c) Notwithstanding the provisions of Section 9.4(b), if at any time during the Term the Commission revokes or issues an amended Commission Certificate that imposes material qualifications or conditions that adversely affect Buyer or Seller, unless Buyer assumes the cost and risk associated with such material qualifications and conditions established in such amended Commission Certificate subject to the agreement of Seller if Seller would be adversely affected, then Buyer agrees to utilize the capacity and energy supplied under this Agreement, without modification, for the purpose of exclusively serving its wholesale electric customers and not its retail electric customers.

ARTICLE 10

[RESERVED]

ARTICLE 11

[RESERVED]

ARTICLE 12

LIABILITY ALLOCATION; LIMITATIONS ON LIABILITY

12.1 Taxes.

12.1.1 Seller shall be responsible for all Taxes imposed by any Governmental Authority on or with respect to the capacity and energy supplied under this Agreement that arise prior to the Point(s) of Receipt. By way of example, such Taxes for which Seller is responsible shall include all ad valorem Taxes with respect to the generating units utilized by Seller to supply power under this Agreement. Buyer shall be responsible for all Taxes imposed by any Governmental Authority on or with respect to the capacity and energy supplied under this Agreement that arise at and from the Point(s) of Receipt. By way of example, such Taxes for which Buyer is responsible shall include Taxes that are the result of the sale or transfer to Buyer of the capacity and energy supplied under this Agreement, or the use of capacity and energy supplied under this Agreement. Buyer will provide Seller with appropriate resale or other exemption certificate(s) with respect to any sales, use and/or gross receipts Taxes that could be based upon the sale or use of capacity and energy supplied under this Agreement.

12.1.2 In the event Seller is required by Law to remit or pay Taxes that are Buyer's responsibility hereunder, Buyer shall promptly reimburse Seller for such Taxes. If Buyer is required by Law to remit or pay Taxes that are Seller's responsibility hereunder, Buyer may deduct the amount of any such Taxes from the amounts due to Seller under Article 6 of this Agreement. If the amount of any such Taxes paid by Buyer that are Seller's responsibility hereunder exceed the amounts due under Article 6 of this Agreement, then Seller shall promptly reimburse Buyer for the excess amount. Each Party shall use

reasonable efforts to implement and administer the provisions of this Agreement in accordance with the intent of the Parties to minimize Taxes so long as neither Party is materially adversely affected by such efforts.

12.2 Indemnification.

12.2.1 Unless otherwise agreed in writing by the Parties, each Party shall defend, indemnify and save harmless the other Party and its officers, directors, trustees, agents, employees and representatives from and against any and all claims, demands, costs or expenses (including reasonable attorneys' fees) for loss, damage or injury to any person or property arising out of or in any way related to this Agreement to the extent such loss, damage or injury occurs on the Indemnifying Party's own side of the Point(s) of Receipt; provided, however, that the Indemnifying Party shall have no indemnification obligation hereunder in respect of any claim, loss, liability, damage, cost or expense to the extent caused by the negligence, wantonness, fraud or willful misconduct of the non-Indemnifying Party.

12.2.2 Nothing in this Agreement shall create a contractual relationship between one Party and the customers of the other Party, nor shall it create a duty of any kind to such customers.

12.3 Limitation of Liability.

12.3.1 EXCEPT AS EXPRESSLY PROVIDED FOR HEREIN, SELLER, ON BEHALF OF ITSELF, EACH OF ITS AFFILIATES AND EACH OF THEIR RESPECTIVE EMPLOYEES, OFFICERS, DIRECTORS, AGENTS, SUCCESSORS AND ASSIGNS, HEREBY DISCLAIMS ANY AND ALL EXPRESS,

IMPLIED OR STATUTORY WARRANTIES CONCERNING EITHER OR BOTH THE CAPACITY OR ENERGY TO BE SOLD BY SELLER HEREUNDER, INCLUDING WITHOUT LIMITATION ANY AND ALL WARRANTIES AS TO MERCHANTABILITY, FITNESS FOR A PARTICULAR PURPOSE, AVAILABILITY, ACCURACY, QUALITY, QUANTITY OR OTHERWISE.

12.3.2 NEITHER PARTY SHALL BE LIABLE TO THE OTHER FOR CONSEQUENTIAL, INCIDENTAL, PUNITIVE, EXEMPLARY OR INDIRECT DAMAGES SUFFERED BY THAT PARTY OR BY ANY CUSTOMER OF THAT PARTY, WHETHER BY VIRTUE OF ANY STATUTE, IN TORT OR CONTRACT, UNDER ANY PROVISION OF INDEMNITY OR OTHERWISE. THE PARTIES INTEND THAT THE LIMITATIONS HEREIN IMPOSED ON REMEDIES AND THE MEASURE OF DAMAGES BE WITHOUT REGARD TO THE CAUSE OR CAUSES RELATED THERETO, INCLUDING, WITHOUT LIMITATION, THE NEGLIGENCE OF ANY PARTY, WHETHER SUCH NEGLIGENCE BE SOLE, JOINT OR CONCURRENT, OR ACTIVE OR PASSIVE.

12.3.3 In the event that any provision of this Section 12.3 is held to be invalid or unenforceable, this Section shall be void and of no effect solely to the extent of such invalidity or unenforceability, and no claim arising out of such invalidity or lack of enforceability shall be made by one Party against the other or its officers, agents, or employees. Notwithstanding the foregoing, this Section 12.3 shall not limit or negate the

right of either Party to be fully indemnified as provided in Section 12.2 or limit the remedies set forth in this Agreement for an Event of Default.

12.3.4 Neither any Affiliate of a Party nor any stockholder, officer, director or employee of a Party or of any Affiliate of a Party shall have any liability to the other Party for the payment of any sums now or hereafter owing by such Party or for the performance of any of the obligations of such Party contained herein, and each of the Parties hereto agrees that all of the obligations of the other Party under this Agreement shall be obligations solely of such other Party and recourse in enforcing said obligations shall only be had against the assets of such other Party; provided that the foregoing provision shall not constitute a waiver, release or discharge of any of the terms, covenants or conditions of this Agreement, and the same shall continue until fully paid, discharged, observed or performed.

ARTICLE 13

EVENT OF DEFAULT AND TERMINATION

13.1 Event of Default. "Event of Default" shall mean the occurrence of any of the following events with respect to a Party (the "Defaulting Party," the other Party being the "Non-Defaulting Party"):

13.1.1 the failure by the Defaulting Party to make, when due, payment of any amount required under this Agreement if such failure is not remedied within ten (10) Business Days after written notice of such failure is given to the Defaulting Party by the Non-Defaulting Party;

13.1.2 any material representation or warranty of the Defaulting Party pursuant to this Agreement shall prove to have been false or misleading in any material respect when made or deemed made unless: (i) the fact, circumstances or condition that is the subject of such representation or warranty is made true within twenty (20) Days after notice thereof has been given to the Defaulting Party; and (ii) such cure removes any adverse effect on the Non-Defaulting Party of such fact, circumstance or condition being otherwise than as first represented;

13.1.3 the Defaulting Party:

(i) makes a general assignment or arrangement for the benefit of its creditors;

(ii) (a) files a petition or otherwise commences, authorizes, or acquiesces in the commencement of a proceeding or case under any bankruptcy or similar Law for the protection of creditors or (b) has such petition filed or proceeding commenced against it and, in the case of a petition filed or proceeding commenced against it, such petition or proceeding results in a judgment of insolvency or bankruptcy or the entry of any order for relief or the making of an order for the winding-up or liquidation of such entity, or is not dismissed, discharged, stayed or restrained within five (5) Business Days of the filing or commencement thereof;

(iii) otherwise becomes bankrupt or insolvent;

(iv) fails or is unable or admits in writing its inability generally to pay its debts as they become due;

(v) is dissolved (other than pursuant to a consolidation, acquisition, amalgamation or merger);

(vi) has a resolution passed for its winding-up, official management or liquidation (other than pursuant to a consolidation, acquisition, amalgamation or merger);

(vii) seeks or becomes subject to the appointment of an administrator, provisional liquidator, conservator, receiver, trustee, custodian or other similar official for all or substantially all of its assets;

(viii) causes or is subject to any event with respect to which it, under the applicable Laws of any jurisdiction, has an analogous effect to any of the events specified in Section 13.1.3 clauses (i) through (vii) (inclusive);

(ix) takes any action in furtherance of, or indicating its consent to, approval of, or acquiescence in, any of the foregoing acts; or

(x) merges with any other entity and the surviving entity does not assume the Defaulting Party's obligations under this Agreement;

13.1.4 the material failure by Defaulting Party to perform any of its material obligations under this Agreement (other than obligations which are otherwise specifically covered in this Section 13.1 as a separate Event of Default) if such failure is not otherwise excused in accordance with this Agreement, which such failure materially and adversely affects the ability of such Defaulting Party to continue to perform its obligations under this Agreement and such failure continues uncured for sixty (60) Days after notice thereof from the other Party; provided, however, if such failure is not capable of being cured within such

period of sixty (60) Days with the exercise of reasonable diligence, then such cure period shall be extended for an additional reasonable period of time (not to exceed one hundred twenty (120) Days), so long as the Party is exercising reasonable diligence to cure such failure;

13.1.5 the Defaulting Party defaults on obligations under one or more agreements or instruments in respect of debt and such default continues after the applicable grace period, if any, specified in such agreement or instrument if the principal amount of such agreement or instrument equals or exceeds ten percent (10%) of the Defaulting Party's equity, and such default results in such debt becoming, or becoming capable at such time of being declared, due and payable prior to its stated maturity, whether or not such debt is in fact declared due and payable; or

13.1.6 the failure of a Party to comply with the requirements of Section 17.1.

13.2 Rights Under Agreement. Except as otherwise provided herein, each Party reserves to itself all rights, counterclaims, and other defenses which it is or may be entitled to arising from or out of this Agreement.

13.3 Remedies Upon Default. Upon the occurrence of an Event of Default that is not cured within the applicable cure period identified in this Agreement, the Non-Defaulting Party shall have the right to terminate this Agreement upon written notice to the Defaulting Party in addition to any other right or remedy the Non-Defaulting Party may have under this Agreement or at law or equity, except as otherwise limited by this Agreement.

ARTICLE 14

DISPUTE RESOLUTION

14.1 Applicability. Except for matters requiring immediate injunctive relief and matters addressed in Section 6 of the Service Schedule, any dispute or claim between the Parties arising out of or relating in any way to this Agreement will be resolved in accordance with the dispute resolution process set forth in this Article 14.

14.2 Notice of Dispute. In the event any dispute or claim arises between the Parties, a Party (the "Disputing Party") must provide the other Party (the "Responding Party") with a notice of each issue in dispute (which notice must be provided in accordance with Section 17.7), a proposed means for resolving each such issue in dispute, and support for such position (including copies of supporting documentation or other information) (the "Notice of Dispute"). Within fifteen (15) Days after receiving a Notice of Dispute, the Responding Party will provide the Disputing Party with a notice acknowledging receipt of the Notice of Dispute, identifying each additional issue (if any) with respect to the disputed issue (or issues) raised by the Notice of Dispute, a proposed means for resolving each issue in dispute, and support for such position (including copies of supporting documentation or other information) (the "Dispute Response").

14.3 Dispute Resolution by Senior Officers. Each Party shall designate its Senior Officer to meet, in person, to discuss the matter and employ good faith efforts to promptly reach a resolution of each such issue in dispute. Each such Senior Officer will have authorization, subject to any necessary Board approval, to resolve any issue in dispute. The Senior Officers will meet, in person or by telephone, not later than ten (10) Days after the date the Dispute Response is received by the Party submitting the Notice of Dispute and as mutually agreed thereafter. If after

thirty (30) Days from such initial meeting by the Senior Officers, the dispute is not resolved to the mutual satisfaction of the Parties, then either Party may seek remedies at law or in equity.

ARTICLE 15

REPRESENTATIONS AND WARRANTIES

15.1 Execution. Each Party represents and warrants to the other Party as of the Effective Date that: (i) it has all the necessary corporate and legal power and authority and has been duly authorized by all necessary corporate action to enable it to lawfully execute, deliver and perform under this Agreement; and (ii) it is a valid legal entity duly organized and validly existing in good standing under the Laws of the state of its formation and is, to the extent required, qualified to do business in the state where it is organized.

15.2 Binding Obligations. Each Party represents and warrants to the other Party that as of the Effective Date that this Agreement is the valid and binding obligation of such Party, enforceable against such Party in accordance with its terms, except as such enforceability may be limited by bankruptcy, insolvency, reorganization, moratorium or other similar Laws affecting enforcement generally, and by equitable principles regardless of whether such principles are considered in a proceeding at law or in equity.

15.3 Execution and Consummation. Each Party represents and warrants to the other Party that as of the Effective Date the execution and delivery of this Agreement, the consummation of the transactions contemplated hereby and the fulfillment of and compliance with the provisions of this Agreement do not and will not conflict with any of the terms, conditions or provisions of its organizational documents or any Law applicable to it or result in a breach or default under any evidence of its indebtedness or any other agreement or instrument to which it is a party or by which

it or any of its property is bound which has a reasonable likelihood of materially and adversely affecting the consummation of the transactions contemplated hereby or the performance by the Party of any of its obligations under this Agreement.

15.4 Actions and Proceedings. Each Party represents and warrants to the other that as of the Effective Date there is no pending or, to the knowledge of such Party, threatened action or proceeding affecting such Party before any Governmental Authority that has a reasonable likelihood of materially adversely affecting or reasonably threatening the ability of such Party to perform its obligations under this Agreement or the validity or enforceability of this Agreement against it and that there are no bankruptcy proceedings pending or being contemplated by it or, to its knowledge, threatened against it.

15.5 Absence of Certain Events. Each Party represents and warrants to the other Party that as of the Effective Date no Event of Default attributable to it has occurred and is continuing and no such event or circumstance would occur as a result of its entering into or performing its obligations under this Agreement.

ARTICLE 16

CONFIDENTIALITY

16.1 Confidential Information. "Confidential Information" means business or technical information of a Party rightfully in the possession of such Party, which information derives independent actual or potential commercial value from not being generally known or readily ascertainable through independent development or reverse engineering by Persons who can obtain economic value from its disclosure and use, and which information is the subject of efforts that are reasonable under the circumstances to maintain its secrecy. Each page of Confidential

Information shall be stamped or marked as such prior to transmittal to the receiving party. Confidential Information consists of information designated as confidential and furnished by a Party to another Party in discussions leading up to execution of this Agreement (including in Seller's proposals to Buyer) and during the Term of this Agreement, and the terms, conditions and pricing information contained in this Agreement.

16.2 Disclosure of Confidential Information.

16.2.1 Each Party agrees that during the Term of this Agreement and for a period of three (3) years from the date of termination of this Agreement it will not, without the written consent of the other Party or as otherwise provided herein, disclose Confidential Information of another Party to any other party; provided, however, each Party shall be entitled to disclose Confidential Information to its (or its Affiliates') agents, employees, officers, directors, trustees, representatives, contractors, attorneys, advisors, lenders, accountants, rating agencies, underwriters, consultants and advisors who need to know such information in connection with the performance of their duties or services for such Party or Affiliates or in connection with the analysis, issuance or rating of any debt or equity securities or financial activities of such Party or Affiliates; provided, further, that such parties shall be bound by an obligation to maintain the confidentiality of such Confidential Information and such Party shall be responsible for any use or disclosure by such parties of any Confidential Information inconsistent with this Article 16.

16.2.2 To the extent Seller is required to provide Confidential Information in this Agreement to FERC, Seller shall seek confidential treatment of such Confidential Information from FERC, and Buyer will provide reasonable cooperation in connection with

such request. Notwithstanding the foregoing, the Parties acknowledge that certain Confidential Information may need to be disclosed in filings with FERC which may become publicly available. In the event this Agreement becomes publicly available, Seller will promptly notify Buyer once Seller learns of this fact; provided, however, that regardless of whether such notification is provided, the provisions of this Article 16 shall no longer apply to this Agreement if this Agreement becomes publicly available as a result of filings with FERC or otherwise.

16.2.3 Either Party may file this Agreement and Confidential Information with the Securities and Exchange Commission ("SEC") as may be necessary under Laws in connection with such Party's application to the SEC for such orders and approvals as may be required for financing and/or the issuance and sale of interests in or debt issued or to be issued by such Party and/or its Affiliates. The filing Party shall request confidential treatment of this Agreement and Confidential Information in connection with such filing; however, the Parties acknowledge that such request may be denied in whole or in part, and accordingly, that confidential treatment may not be afforded by the SEC to such information. In addition, each Party may disclose Confidential Information as required by the SEC pursuant to the Securities and Exchange Act of 1934, as amended, and any rule or regulation promulgated thereunder.

16.2.4 Buyer may file this Agreement and Confidential Information with the GPSC and Seller with the MPSC, as applicable, as may be necessary under Laws, including without limitation, in connection with any application (if any) to the GPSC and MPSC, as applicable, for such orders and approvals as may be required in connection with such

Party's respective obligations under this Agreement, and/or the issuance and sale of interests in or debt issued or to be issued by such Party, and/or state regulatory cost treatment of such Party's respective obligations under this Agreement. Buyer and Seller, as applicable, shall request confidential treatment of this Agreement and Confidential Information in connection with such filing; however, the Parties acknowledge that such request may be denied in whole or in part, and accordingly, that confidential treatment may not be afforded by the GPSC or the MPSC, as applicable, to such information.

16.2.5 Nothing in this Section 16.2 shall prohibit or otherwise limit the use or disclosure of Confidential Information if such Confidential Information: (a) was previously known to the disclosing or using Party unrelated to this Agreement without an obligation of confidentiality; (b) was developed by or for the disclosing or using Party unrelated to this Agreement using non-confidential information; (c) was acquired by the disclosing or using Party from a third Person which is not, to the disclosing or using Party's knowledge, under an obligation of confidentiality with respect to such information; or (d) is or becomes publicly available other than through a manner inconsistent with this Article 16.

16.2.6 Notwithstanding anything in this Article 16 to the contrary, if a Party is required by applicable Law or in the course of administrative or judicial proceedings or investigations, to disclose to third parties, Confidential Information of the other Party or this Agreement, such required Party may make disclosure of such information; provided, however, that all reasonable steps are taken by such Party to assure continued confidential treatment by the relevant administrative, regulatory or judicial agencies or other recipient and provided further that as soon as such Party learns of the disclosure request or

requirement or otherwise intends to disclose any such Confidential Information pursuant hereto and prior to making disclosure, such Party, to the extent permitted by Law, notifies the other Party of the requirement, request or intention and the terms thereof and such other Party may challenge the disclosure requirement, request or intention or seek a protective order or other appropriate remedy. The Party required to disclose Confidential Information, at the expense of the Party whose Confidential Information would be disclosed, shall attempt to minimize the disclosure of such Confidential Information consistent with applicable Law and attempt to obtain proprietary or confidential treatment of such Confidential Information by the Person to whom such Confidential Information will be disclosed (and if practicable, reasonably prior to any such disclosure). If, in the absence of a protective order or other appropriate remedy, the Party required to disclose Confidential Information is nonetheless, in the written opinion of counsel, legally compelled to disclose such Confidential Information or otherwise may become subject to contempt or other censure or penalty, such Party required to disclose may, in such instance but not otherwise, without liability hereunder, disclose that portion of such Confidential Information which and to whom such counsel advises the required Party is legally required to be disclosed (but none other).

16.3 Remedies. A breach of the confidentiality obligations of Section 16.2 by any Person with whom the receiving Party has shared Confidential Information of the disclosing Party shall be deemed a breach of this Article by the receiving Party. The Parties shall be entitled to all remedies available at law or in equity to enforce, or seek relief in connection with, this confidentiality obligation; provided that all monetary damages shall be limited to actual direct

damages and that a breach of the confidentiality obligations of Section 16.2, notwithstanding anything to the contrary in this Agreement, shall not give rise to a right to suspend or terminate any ongoing transaction under this Agreement or result in an Event of Default hereunder.

16.4 Return of Confidential Information. Except as specifically required otherwise by Law, upon the request of a disclosing Party, the receiving Party shall return or destroy all written Confidential Information (including written confirmation of oral communications) provided by the disclosing Party which was stamped "CONFIDENTIAL INFORMATION" and shall not retain any copies of such written Confidential Information. In the event of such request (but except as required otherwise by Law), all copies, documents, analyses, compilations, studies or other materials prepared by the returning Party or its representatives that contain or reflect Confidential Information shall be destroyed and no copy thereof shall be retained (such destruction to be confirmed in writing by a duly authorized officer of the returning Party). Notwithstanding the foregoing provisions of this Article 16, the Parties agree that neither Party shall be required to return or destroy such Party's execution copy of this Agreement or those materials that such Party maintains in the ordinary course of business as the basis for the decision to enter into the Agreement, provided that all such Confidential Information so retained will continue to be maintained as confidential.

ARTICLE 17

MISCELLANEOUS PROVISIONS

17.1 Assignment.

17.1.1 Except as provided in this Section 17.1.1, neither Party may assign outright or collaterally or pledge or grant a security interest in this Agreement or its rights or

obligations under this Agreement without the prior written consent of the other Party (which consent shall not be unreasonably withheld or delayed). No assignment by a Party of this Agreement or its rights or obligations under this Agreement shall relieve the assigning Party of liability for its obligations under this Agreement without the written release of the other Party. Such release shall not be withheld or unreasonably delayed if the Assignment Conditions (defined below) are satisfied.

17.1.2 The non-assigning Party's obligation to recognize or perform for any Person claiming or otherwise holding rights in or under this Agreement by outright assignment or through a foreclosure or other exercise of rights pursuant to a collateral assignment, pledge of or grant of security interest in this Agreement (or any related rights) permitted by this Agreement (an "Assignee") shall be subject to such Assignee: (i) establishing that it has the legal power and authority to perform and satisfy the obligations then and thereafter to become due to the non-assigning Party under this Agreement; (ii) having cured all existing Events of Default (other than Events of Default with respect to which the non-assigning Party is the Defaulting Party) under this Agreement; and (iii) having executed and delivered to the non-assigning Party and being in compliance with an assignment and assumption agreement whereby the Assignee assumes and agrees to satisfy all conditions and pay and perform all obligations in favor of the non-assigning Party then existing and/or thereafter arising under this Agreement ("Assignment Conditions"). Any attempted assignment, whether outright, by way of foreclosure or exercise of any rights pursuant to a collateral assignment, pledge or grant of security interest in this Agreement or any related rights or

otherwise, which is not in compliance with the terms of this Agreement shall be voidable and ineffective, at the option of the non-assigning Party.

17.2 No Partnership. The Parties do not intend for this Agreement to, and this Agreement shall not, create any joint venture, partnership, association taxable as a corporation, or other entity for the conduct of any business for profit.

17.3 Successors and Assigns. This Agreement shall inure to the benefit of and be binding upon any respective successors and assigns of the Parties.

17.4 No Third Party Benefit. Nothing in this Agreement shall be construed to create any duty, obligation or liability of Seller or Buyer to any Person not a Party to this Agreement, including any customer of Buyer.

17.5 No Waiver. The failure of Seller or Buyer to enforce any provision or provisions of this Agreement shall not in any way be construed as a waiver of any such provision or provisions as to any future violation thereof, nor prevent it from enforcing each and every other provision of this Agreement at such time or at any time thereafter. The waiver by either Seller or Buyer of any right or remedy shall not constitute a waiver of its right to assert said right or remedy, at any time thereafter, or any other rights or remedies available to it at the time of or any time after such waiver. No waiver of all or any part of this Agreement shall be valid unless it is reduced to a writing, expressly states that the Parties agree to such waiver, and is duly executed by the Parties.

17.6 Amendments. This Agreement may be amended only by a written instrument, duly executed by each of the Parties, which has received all approvals of Governmental Authorities with competent jurisdiction necessary for the effectiveness thereof.

17.7 Notice. Any notice, demand, request, statement, or correspondence provided for in this Agreement, or any notice which a Party may desire to give to the other in connection with this Agreement, shall be in writing (unless otherwise expressly provided by this Agreement) and shall be considered duly delivered when received by hand delivery, first-class mail, facsimile, or by overnight delivery, at the address(es) and to the attention of the person(s) listed below. However, if actual delivery occurs at a time other than between the Hours of 0800 and 1700 Central Prevailing Time on a Business Day (each a "Business Hour"), delivery shall be deemed to have occurred in the next Business Hour after actual delivery. Each Party may designate a different person and address by sending written notice to the other Party, to be effective no sooner than ten (10) days after the date of notice.

If given to Seller, it shall be addressed to:

Mississippi Power Company
2992 West Beach Blvd
PO Box 4079
Gulfport, MS 39502
Attn: Vice President, General Counsel, Corp Sec & CCO

with a copy to:

Mississippi Power Company
2992 West Beach Blvd
PO Box 4079
Gulfport, MS 39502
Attn: Vice President, Treasurer & CFO

Southern Company Services, Inc.
600 North 18th Street
BIN 15N-8230
Birmingham, Alabama 35203
Attn: Vice President, Southern Wholesale Energy
Facsimile: (205) 257-1872

and

Southern Company Services, Inc.
3535 Colonnade Parkway
BIN EC S-400
Birmingham, Alabama 35243
Attn: Financial and Contract Services Manager
Facsimile: (205) 257-5777

and, if given to Buyer, it shall be addressed to:

Georgia Power Company
241 Ralph McGill Blvd
BIN 10221
Atlanta, Georgia 30308
Attn: Vice President, Pricing and Planning

with a copy to:

Georgia Power Company
241 Ralph McGill Blvd
BIN 10180
Atlanta, Georgia 30308
Attn: Deputy General Counsel, Legal Department

17.8 Counterparts. This Agreement may be executed in multiple counterparts, each of which shall be deemed an original but all of which together shall constitute one and the same instrument.

17.9 Articles and Sections Headings. The descriptive headings of the various Articles and Sections of this Agreement have been inserted for convenience of reference only and shall in no way modify or restrict any of the terms or provisions hereof.

17.10 Governing Law. The validity, interpretation and performance of this Agreement and each of its provisions shall be governed by the Laws of the State of New York (without giving effect to the principles of conflict of laws).

17.11 Severability. In the event any provision of this Agreement is declared invalid or unenforceable by a final, non-appealable order of any Governmental Authority, the Parties shall promptly renegotiate to restore this Agreement as near as possible to its original intent and effect.

17.12 Further Assurances. If either Party reasonably determines or is reasonably advised that any further instruments or any other things are necessary or desirable to carry out the terms of this Agreement, the other Party shall execute and deliver all such instruments and assurances and do all things reasonably necessary and proper to carry out the terms of this Agreement.

17.13 Entire Agreement. This Agreement and the schedule and appendices attached hereto constitute the entire agreement between the Parties as of the time of execution relating to the subject matter contemplated by this Agreement and supersedes all prior agreements, whether oral or written.

[REMAINDER OF PAGE INTENTIONALLY LEFT BLANK.]

IN WITNESS WHEREOF, the Parties have caused this Agreement to be executed and delivered by their respective duly authorized representatives as of the date first above written.

"Seller"

MISSISSIPPI POWER COMPANY

By: _____

Name: Matthew P. Grice

Title: Vice President, Treasurer & CFO

"Buyer"

GEORGIA POWER COMPANY

By: _____

Name: Roderick W. Anderson

Title: Senior Vice President & SPO

POWER SUPPLY SERVICE SCHEDULE

1. **Definitions.**

The capitalized terms set forth in this Power Supply Service Schedule shall have the meanings given to them in the Agreement and this Power Supply Service Schedule. The following terms shall have the respective meanings set forth as follows:

"**AIER**" means the Associated Interchange Energy Rate as such term is defined in the IIC, as may be modified or amended from time to time.

"**Agreement**" means that certain Power Supply Agreement between Buyer and Seller to which this Service Schedule is attached.

"**Balancing Authority**" means any NERC recognized entity responsible for ensuring generating resources and loads are in balance within an applicable Balancing Authority Area and supporting interconnection frequency in real time.

"**Balancing Authority Area**" means the collection of generation, transmission, and loads within the metered boundaries of the Balancing Authority.

"**Buyer Contract Capacity Ratio**" means, for a given Year during the Service Term, the result of: (a) the Contract Capacity amount; divided by (b) the Seller Generating Resources Capacity Rating.

"**Contract Capacity**" means, for the applicable period during the Service Term, the electric generating capacity in the amount specified in Section 2.5 of this Service Schedule.

"**Energy**" means, during a given Hour, the electric energy associated with the Contract Capacity to be delivered by Seller pursuant to the Agreement, including this Service Schedule.

"**NERC**" means the North American Electric Reliability Corporation, a not-for-profit international regulatory authority designated by FERC as the Electric Reliability Organization whose mission is to assure the reliability and security of the bulk power system in North America, or any other regulatory authority succeeding to the powers and functions thereof.

"**Seller Generating Resources**" means, at any given time, mean, the electric generating units owned or controlled by Seller that are (i) in commercial operation and (ii) are submitted to Southern Dispatch.

"**Seller Generating Resources Capacity Rating**" means, at any given time, the net summer capacity rating, in MW, of the Seller Generating Resources, as determined in accordance with the IIC.

"**Southern Dispatch**" means the process by which the Southern Operating Companies schedule and control, manually or automatically, the energy utilized from a portfolio of resources,

in accordance with the IIC, in order to increase or decrease the electric energy delivered from such resources into the Balancing Authority Control Area to reliably meet the load obligations of the Balancing Authority Control Area.

"**Transmission Risk**" means the ramifications (performance, economic or otherwise) resulting from the unavailability of transmission service, including an interruption or curtailment of transmission service.

2. **Sale and Delivery of Energy.**

2.1 Commencing on January 1, 2024, and continuing through the end of the Service Term, subject to the terms and conditions of the Agreement, including this Service Schedule, Seller shall provide the Energy associated with and up to the Contract Capacity, in accordance with and as specified in accordance with Section 3 of this Service Schedule. Buyer shall receive and purchase such Energy pursuant to the terms of the Agreement and this Service Schedule.

2.2 Seller shall deliver the Energy to Buyer at the Point(s) of Receipt. Title, custody, and control of such Energy shall pass to Buyer at the Point(s) of Receipt.

2.3 Buyer shall have the Transmission Risk and risk of loss for all Energy delivered to Buyer under this Agreement at and after the Point(s) of Receipt.

2.4 Seller shall be entitled to supply the Contract Capacity and the Energy provided under this Service Schedule from any generating units to which Seller is entitled by ownership, contract or otherwise to the output.

2.5 The Contract Capacity available to the Buyer for the applicable period during the Service Term is as specified below:

Year	Contract Capacity (MW)
2024	750
2025	750
2026	750
2027	750
2028	750

2.6 **REDACTED REDACTED REDACTED

3. **Energy Utilization.**

For each Hour of the Service Term, Buyer shall be entitled to and shall receive the Energy associated with its Contract Capacity up to the Contract Capacity amount determined in such Hour in accordance with Southern Dispatch.

4. **Availability of Supply.**

4.1 The Contract Capacity shall be available for energy utilization pursuant to Section 3 above, except as set forth in Section 4.2 below.

4.2 In the event that Seller or its agent determines that adequate resources are not reasonably available with which to serve Seller's Firm and Native Load requirements (including the energy requirements of Buyer under the Agreement and this Service Schedule) or that it is necessary or appropriate for Seller to shed, interrupt or curtail such Firm and Native Load requirements, then Seller shall be entitled to shed, curtail and interrupt the delivery of Energy pursuant to this Service Schedule in the same proportion that Seller's own Firm and Native Load requirements are shed, curtailed or interrupted. Seller shall resume deliveries of Energy under this Agreement consistent with the restoration of service to Seller's own Firm and Native Load.

4.3 Nothing in this Section 4 is intended to contravene any provision of the Southern OATT pertaining to the curtailment of transmission service.

5. **Calculation of Monthly Payments.**

For each Month of the Service Term, Buyer shall pay to Seller the Monthly Capacity Payment and the Monthly Energy Payment as described below.

5.1 Monthly Capacity Payment.

For each Month of the Service Term, the Monthly Capacity Payment ("MCP") shall be determined as follows:

MCP = CC * CCP * 1000

Where:

CC = the Contract Capacity for such Month of the applicable Year; and

CCP = the Contract Capacity Price for such Month of the applicable Year, as stated in Table 1 below.

Except in the event Seller reduces the Contract Capacity amount as envisioned under Section 2.6 above, the Monthly Capacity Payment shall not be reduced for any reason, including for the circumstance of a shedding or curtailment deliveries under Section 4 of

this Service Schedule or the unavailability, curtailment or interruption of transmission service at or from the Point(s) of Receipt.

Table 1
Contract Capacity Price ($/kW-month)

2024	2025	2026	2027	2028
REDACTED	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**

5.2 Monthly Energy Payment.

For each Month of the Service Term, the Monthly Energy Payment shall be equal to the sum of the Hourly Energy Charges ("HEC") for all Hours of such Month. For each Hour, the HEC shall be determined as follows:

HEC = HE * HEP

Where:

HE = the amount of Hourly Energy (in MWh) delivered by Seller to Buyer under this Service Schedule for the applicable Hour.

HEP = the Hourly Energy Price (in $/MWh), **REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED.**

The HEP is subject to true-ups or corrections, including charges or credits, identified by either Party subsequent to the last Monthly invoice as set forth in Section 7.1 of the Agreement.

6. Change in Law.

6.1 Occurrence of Changes in Law. The Parties acknowledge that a change of a Law (excluding a change in regulation associated with the formation of RTOs, ITCs or ISOs as specifically provided for in Section 5.3 of the Agreement), a change in interpretation of a Law, or a change in the specified standards or objective criteria contained in a permit, license or other approval on or after the Effective Date may cause the fixed or variable expenditures, or both, of the Seller Generating Resources used to provide the power supply service under this Agreement to materially increase or decrease (each, a "Change in Law"). In the event a Change in Law occurs, Buyer shall be responsible for its pro rata share of any such increased costs and expenses (in the aggregate, including fixed, variable, and capital costs and expenses) incurred by Seller that result from complying with, recognizing, or acting in response to a Change in Law. Any such fixed, variable, and capital costs and expenses, including overheads as appropriate, shall be recovered by Seller from Buyer on a pro-rata basis, using the Buyer Contract Capacity Ratio.

6.2 Change in Law Notice. In the event either Party determines a Change in Law has occurred, such Party (the "CIL Initiating Party") may initiate discussions with the other Party (the "CIL Responding Party") to determine the appropriate adjustment to the billing or amendment to the Agreement as described in this Section 6 by delivering written notice to the Affected Party of such Change in Law event (each, a "Change in Law Notice").

6.2.1 The Change in Law Notice will include applicable information reasonably available to the CIL Initiating Party supporting its Change in Law determination, including the CIL Initiating Party's calculation of the projected change in the Seller Generating Resources costs (either increase or decrease) used to provide the power supply service under this Agreement resulting from the Change in Law.

6.2.2 Upon delivery of the Change in Law Notice, Seller will initiate a request with SCS to prepare a good faith calculation of the effect of such purported Change in Law. The Parties agree to reasonably cooperate and provide relevant information to SCS as requested to permit SCS to prepare a cost impact calculation and a proposed billing adjustment under this Agreement and/or a proposed amendment to this Agreement to allocate the cost impact of such purported Change in Law between the Parties (the "Proposed CIL Adjustment").

6.2.3 Upon receipt by the Parties of the Proposed CIL Adjustment from SCS, the Parties shall engage in discussions for a period of up to ninety (90) Days (the "CIL Resolution Period") to resolve any differences with respect to the calculation, cost information supporting the calculation or the Proposed CIL Adjustment.

6.3 Change in Law Dispute Resolution Process. If the Parties have not agreed upon a proposed billing adjustment under this Agreement and/or a proposed amendment to this Agreement to allocate the cost impact of such purported Change in Law between the Parties by the expiration of the CIL Resolution Period, then either Party has the right to initiate a dispute resolution process by engaging a nationally recognized accounting firm that is not then the independent auditor for either Party and is selected by the mutual agreement of the Parties (the "Neutral Auditors").

6.3.1 Each Party agrees to execute, if requested by the Neutral Auditors, a reasonable engagement letter, including customary indemnities. All fees and expenses related to the work to be performed by the Neutral Auditors shall be borne equally by each Party. All fees and expenses related to the work to be performed by the Neutral Auditors shall be borne equally between the Parties.

6.3.2 The Neutral Auditors shall review the purported Change in Law and the calculation and supporting cost information used to develop the Proposed CIL Adjustment. The Neutral Auditors shall act as an arbitrator to make an independent decision as to whether a Change in Law has occurred and, if so, whether the Proposed CIL Adjustment has been determined correctly and allocated appropriately between Seller and Buyer.

6.3.3 Each Party shall submit its proposed resolution, including its calculation

and supporting information, regarding the amount by which Seller's costs for providing service under the Agreement have changed or will change as a result of the Change in Law and the date upon which Seller will begin to recover such amount from or credit such amount to Buyer.

6.3.4 If the Neutral Auditors conclude that a Change in Law has occurred, the Neutral Auditors will either (i) accept the Proposed CIL Adjustment or (ii) provide an alternate billing adjustment under this Agreement and/or a amendment to the Agreement to allocate the cost impact of such Change in Law between the Parties. The Neutral Auditors' determination shall be set forth in a written statement delivered to both Parties and shall be final, binding and conclusive.

6.3.5 Invoices to Buyer will be adjusted accordingly within thirty (30) Days of the Neutral Auditors' notification to the Parties.

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Execution Version

CONTRACT FOR THE

PURCHASE OF FIRM CAPACITY AND ENERGY

FROM THE SANTA ROSA ENERGY CENTER

BETWEEN

GEORGIA POWER COMPANY

AND

SANTA ROSA ENERGY CENTER LLC

October 22, 2023

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CONTRACT FOR THE PURCHASE OF FIRM CAPACITY AND ENERGY

THIS POWER PURCHASE AGREEMENT ("Agreement"), dated as of October 22, 2023 (the "Execution Date"), is between Georgia Power Company, a corporation organized and existing under the laws of the state of Georgia, having its principal place of business in Atlanta, Georgia ("Buyer"), and Santa Rosa Energy Center, LLC, a limited liability company organized and existing under the laws of the state of Delaware ("Seller").

W I T N E S S E T H:

WHEREAS, Seller desires to sell, and Buyer desires to purchase, capacity and associated energy and Ancillary Services from the Facility; and

WHEREAS, the Parties desire to set forth the terms and conditions upon which the sale and purchase of capacity and associated energy and Ancillary Services may be conducted between the Parties.

NOW, THEREFORE, for and in consideration of the premises, the mutual promises and agreements set forth herein and other good and valuable consideration, the receipt, sufficiency, and adequacy of which are hereby acknowledged, Buyer and Seller, each intending to be legally bound, agree as follows:

ARTICLE 1

DEFINITIONS

1.1 Certain Definitions. In addition to the initially capitalized terms and phrases defined in the preamble of this Agreement, the following initially capitalized terms and phrases as and when used in this Agreement shall have the respective meanings set forth below:

1.1.1 "Adjustment Period" - has the meaning assigned in Section 9.2.3.

1.1.2 "Affiliate" - means any Person directly or indirectly controlling or controlled by or under direct or indirect common control of a specified Person. For purposes of this definition, "control" means the power to direct the management and policies of such Person, directly or indirectly, whether through the ownership of voting securities, by contract or otherwise. For purposes of this Agreement, it shall be assumed that the direct or indirect owner of fifty percent (50%) or more of the outstanding stock or

other equity interest of a Person has "control" of such Person. The terms "controlling" and "controlled" have meanings correlative to the foregoing.

1.1.3 "After-Tax Basis" - means, with respect to any payment received or deemed to have been received by any Person, the amount of such payment (the "base payment") supplemented by a further payment (the "additional payment") to that Person so that the sum of the base payment plus the additional payment shall, after deduction of the amount of all Taxes required to be paid by such Person in respect of the receipt or accrual of the base payment and the additional payment (taking into account any credits or deductions arising from the underlying loss, the base payment and the additional payment and the timing thereof), be equal to the amount required to be received. Such calculations shall be made on the basis of the assumption that the recipient is subject to U.S. federal income taxation at the highest applicable statutory rate applicable to corporations for the relevant period or periods, and is subject to state income taxation at the highest applicable statutory rates applicable to corporations in the relevant jurisdiction for the relevant period or periods.

1.1.4 "AGC" or "Automatic Generation Control" - means, generally, the equipment and capability of an electric generation facility automatically to adjust the generation quantity within the applicable balancing authority with the purpose of interchange balancing and means, specifically, the Facility's capability of accepting a set point electronically and the automatic adjustment and regulation of the Facility's energy production.

1.1.5 "Air Permit" - has the meaning assigned in Section 11.3.

1.1.6 "Alternate Delivery" - means delivery of capacity and energy from an Alternate Resource to an Alternate Delivery Point.

1.1.7 "Alternate Delivery Point" - means any point of interconnection between the Alternate Resource and the Transmission System, or the point(s) of interface between the transmission system to which the Alternate Resource is interconnected and the Transmission System, (i) at which Buyer is capable of receiving energy in the quantity to be delivered at such point pursuant to the Southern OATT, (ii) from which Buyer is able to obtain firm network transmission service in order to deliver all of the energy from the applicable Alternate Resource from such point to serve its native load customers at no additional cost to Buyer or its customers, and (iii) from which Buyer is able to transmit such energy to its loads without

being required to either materially change the output of generating resources available to Buyer or materially change the schedule of its preexisting power purchases or sales (other than purchases or sales pursuant to this Agreement) that results in material economic harm to Buyer.

1.1.8 "Alternate Resource" - means a generating resource (other than the Facility) for which Seller (or an energy marketer acting as an agent therefor) has an unencumbered first call right, which is connected to the Transmission System, either directly or through other transmission systems, and which in Buyer's sole judgment is reasonably reliable to meet Buyer's Schedule.

1.1.9 "Alternate Resource Delivery Hours" or "ARDH" - has the meaning assigned in **Appendix A**, Section C-1.

1.1.10 "Ancillary Services" - means all commercial products other than electrical output that are produced by or related to the Facility during the Term, including spinning reserves, operating reserves, black start capability, balancing energy, regulation service, ramping capability, reactive power and voltage control, frequency control and other ancillary or essential reliability service products which are recognized by the Florida Power & Light Company Transmission System as of the date hereof, Environmental Attributes, any other environmental or regulatory credits or allowances resulting from operation of the Facility (subject to Section 12.3), and any other benefit Buyer otherwise would have realized from or related to the Facility if Buyer rather than Seller had constructed, owned or operated the Facility, it being the Parties' intent that all such benefits and entitlements in addition to electrical output that flow to the owner or operator of the Facility, during the Term, belong to Buyer at no additional cost to Buyer. However, if a commercial product is not produced by the Facility, Seller shall not be required to acquire such commercial product in the market in order to comply with this Agreement. For the avoidance of doubt, Ancillary Services do not include: (i) any federal, state or local tax attributes arising from the ownership of the Facility, including depreciation deductions; (ii) grants in lieu of investment tax credits or any similar financial payment or grant with respect to the Facility or the metered electric energy output thereof; (iii) Facility NOx Allowances or Facility SO_2 Allowances or (iv) the metered electric energy produced by the Facility.

1.1.11 "Annual Period" - means any one of a succession of consecutive twelve (12)-Month periods during the Term of this Agreement beginning on January 1; provided, that with respect to the first

Annual Period, it will begin on the Delivery Commencement Date and end on December 31 of such calendar year.

1.1.12 "ASC" - means Accounting Standards Codification.

1.1.13 "ASME Performance Test Code" - means the rules and regulations established by the American Society of Mechanical Engineers to govern Performance Tests applicable to the Facility under this Agreement.

1.1.14 "Availability Percentage" - has the meaning assigned in Section 17.1.8.

1.1.15 "Available" - means all times following the Delivery Commencement Date when the Facility or an Alternate Resource (designated pursuant to Section 5.1.4), as the case may be, is not Unavailable.

1.1.16 "Business Day" - means any Day excluding Saturday, Sunday and NERC-defined holidays.

1.1.17 "Buyer" - has the meaning assigned in the preamble.

1.1.18 "Buyer Election Notice" - has the meaning assigned in Section 18.2.5.

1.1.19 "Buyer Security Account" - means an account designated by Seller for the benefit of Buyer, under the exclusive control of Buyer free and clear of all liens (including the liens of any lenders) of any Person or entity other than Buyer. Any Buyer Security Account shall be established and maintained at the expense of Seller and held by a depositary bank acceptable to Buyer pursuant to a control agreement in form and substance reasonably acceptable to Buyer.

1.1.20 "Capacity Shortfall" - has the meaning assigned in Section 5.1.7.1.

1.1.21 "Change of Control" – in respect of a Person, means any transaction or series of related transactions which, if consummated, would result in such Person being an Affiliate of another ultimate parent entity immediately after such transaction. For the purposes of this definition, a Person's ultimate parent entity is the Person who directly or indirectly controls fifty percent (50%) or more of such Person's outstanding capital stock or other equity interests having ordinary voting power and who does not itself have an ultimate parent entity.

1.1.22 "Change of Law" - has the meaning assigned in Section 18.2.1.

1.1.23 "Change of Law Capital Expenditures" - has the meaning assigned in Section 18.2.2.

1.1.24 "Change of Law Notice" - has the meaning assigned in Section 18.2.3.

1.1.25 "Claim" - has the meaning assigned in Section 20.3.1.

1.1.26 "Commercial Start Date" - means April 1, 2024.

1.1.27 "Confidential Information" - means business, financial or technical information rightfully in the possession of either Party, which information derives actual or potential commercial value from not being generally known or readily ascertainable through independent development or reverse engineering by persons who can obtain economic value from its disclosure and use, and includes information furnished or disclosed to the other Party in connection with discussions leading up to execution of this Agreement, including this Agreement. Confidential Information must be designated in writing as confidential by the Party supplying such information (the "Disclosing Party," the other Party being the "Receiving Party"). Confidential Information does not include information which: (i) is or becomes publicly available other than as a result of a violation of this Agreement; (ii) was, at the time of the disclosure, already in the Receiving Party's possession; (iii) is disclosed to the Receiving Party by a third party who, to the Receiving Party's knowledge, is not prohibited from disclosing the information pursuant to any agreement with the Disclosing Party; (iv) the Receiving Party develops or derives without the aid, application or use of the confidential, privileged or proprietary information; or (v) the Receiving Party is required to disclose pursuant to Legal Requirements.

1.1.28 "Consent" - means any approval, consent, authorization or other applicable requirement that is required with respect to the Facility from any jurisdictional Governmental Authority, including, without limitation, all applicable environmental certificates, licenses, permits and approvals.

1.1.29 "Contracted Capacity" - means the full capacity range of the Facility (in MW) being made available to Buyer pursuant to this Agreement, as specified in **Appendix A**, Section A.

1.1.30 "Contracted Capacity Cap" has the meaning assigned in, and as determined pursuant to, **Appendix A**, Section A.

1.1.31 "Costs" - has the meaning assigned in Section 17.3.3.

1.1.32 "CPI" - means the Consumer Price Index (All Urban Consumers, Series ID CUUR0000SA0, All Items (1982 1984 = 100)) (the "CPI") published by the United States Bureau of Labor Statistics. For purposes of calculating the adjustment of an amount at CPI under this Agreement to be effective on a given January 1 ("Modification Date"), the level of the CPI as published in January 2023 shall be compared to the level of the CPI as published for the Month of January in which the applicable Modification Date occurs ("Publication Month"). If such comparison reveals an increase in the level of the CPI from January 2023 to the Publication Month, then the applicable amount shall be increased by the corresponding percentage change as occurred in the CPI, provided that in no event shall the CPI result in a negative adjustment.

1.1.33 "CPT" - means Central Prevailing Time.

1.1.34 "Creditworthy" - means a Person (i) rated by at least two (2) of the three (3) Rating Agencies, (ii) with an investment grade rating from each of the Rating Agencies that have rated such Person such that its senior unsecured debt (or issuer rating if such Person has no senior unsecured debt rating) is rated at least (A) BBB- by S&P, if rated by S&P, (B) Baa3 by Moody's, if rated by Moody's, and (C) BBB- by Fitch, if rated by Fitch, respectively, and (iii) that has satisfactory and verifiable creditworthiness determined in Buyer's sole discretion.

1.1.35 "CT" - means combustion turbine.

1.1.36 "Cure Period" - has the meaning assigned in Section 17.1.9.

1.1.37 "Day" - means a calendar day.

1.1.38 "Defaulting Party" - has the meaning assigned in Section 17.3.1.

1.1.39 "Delivered Energy" - means, for any Hour, the quantity of energy (expressed in MWh) delivered by Seller to the Point of Interconnection or Alternate Delivery Point, as applicable, pursuant to Buyer's Schedule, excluding test energy and including ramp energy delivered to Buyer at the Point of Interconnection.

1.1.40 "Delivery Commencement Date" - the first day of the month after satisfaction or waiver of the condition precedent set forth in Section 2.3.

1.1.41 "Designated Capacity" - has the meaning assigned in, and is determined pursuant to, **Appendix A**, Section A.3.

1.1.42 "Designated Seasonal Base Capacity" – has the meaning assigned in **Appendix A**, Section A-3.

1.1.43 "Dispatch Hours" or "DH" - has the meaning assigned in **Appendix A**, Section C.1.

1.1.44 "Dispute Response" - has the meaning assigned in Section 20.1.

1.1.45 "Disputing Party" - has the meaning assigned in Section 20.1.

1.1.46 "Early Termination Date" - has the meaning assigned in Section 17.3.1.

1.1.47 "Effective Date" - has the meaning set forth in Section 2.1.

1.1.48 "Eligible Collateral" - means (i) a Letter of Credit, (ii) cash deposited into a Buyer Security Account by Seller, or (iii) a Seller Guaranty; provided, however, that at least fifty percent (50%) of any Eligible Collateral required under any provision of this Agreement must be in the form of either a Letter of Credit or cash deposited into a Buyer Security Account, whenever a Seller Guarantor supplying a Seller Guaranty under this Agreement has an investment grade rating such that its senior unsecured debt (or issuer rating if such Person has no senior unsecured debt rating) is not rated at least (i) BBB by S&P, if rated by S&P, (ii) Baa2 by Moody's, if rated by Moody's, and (iii) BBB by Fitch, if rated by Fitch, respectively. For the purposes of the immediately preceding sentence, a Person is not required to have a senior unsecured debt rating (or issuer rating if such Person has no senior unsecured debt rating) from each of S&P, Moody's and Fitch, but must have the requisite senior unsecured debt rating (or issuer rating if such Person has no senior unsecured debt rating) as set forth above from at least two (2) of the three (3) Rating Agencies.

1.1.49 "Eligible Collateral Amount" – means **REDACTED REDACTED**.

1.1.50 "Environmental Attributes" - means (i) any and all fuel-related, emissions-related, air quality-related or other environmental-related aspects, claims, characteristics, benefits, credits, reductions, offsets, savings, allowances, efficiencies, certificates, tags, attributes, demand reductions or similar products or rights (including all of those relating to greenhouse gases and all green certificates, green tags, renewable certificates, renewable energy credits, and CO2 credits and all of those that otherwise arise or result from the generation of energy from the Facility, and all of those arising or resulting from the existence of the Facility) (a) howsoever titled and whether known or unknown, (b) whether existing as of the Execution Date or at any time during the Term, and (c) whether such Environmental Attributes

have been certified or verified under any renewable standard, and (ii) any environmental benefit Buyer otherwise would have realized from or related to the Facility if Buyer rather than Seller had constructed, owned or operated the Facility; provided, however, that any such environmental benefit could be realized by Seller. Environmental Attributes include any such Environmental Attributes that could qualify or do qualify for application toward compliance with any local, state, federal or international renewable energy portfolio standard, green pricing program, renewable energy program, carbon reduction or greenhouse gas reduction initiative, electricity savings program, licensing requirement, verification or certification procedure, federal contract, or other environmental program, incentive mandate or objective, in each case whether voluntary or mandatory, and whether created by a Legal Requirement, or by any Governmental Authority, partnership, coalition, advisory committee, or independent certification board, group or scientific panel. Environmental Attributes include the exclusive right to report such Environmental Attributes to any Governmental Authority or other Person. Environmental Attributes do not include: (I) any federal, state or local tax attributes arising from the ownership of the Facility, including depreciation deductions; (II) grants in lieu of investment tax credits or any similar financial payment or grant with respect to the Facility or the metered electric energy output thereof; (III) Facility NOx Allowances or Facility SO_2 Allowances or (IV) the metered electric energy produced by the Facility.

1.1.51 "EPA" - means the U.S. Environmental Protection Agency.

1.1.52 "Equivalent Unplanned (Forced) Outage Hours" or "EFDH" - means the sum of the products of each hour in which the Facility experiences a Forced Derate times the size of the derating reduction, divided by the Designated Capacity, and as further defined in **Appendix A**, Section C-1.

1.1.53 "Event of Default" - means an event described in Section 17.1 for Seller and in Section 17.2 for Buyer.

1.1.54 "Excess Capital Expenditures Notice" - has the meaning assigned in Section 18.2.4.

1.1.55 "Excess Change of Law Capital Expenditures" - has the meaning assigned in Section 18.2.4.

1.1.56 "Execution Date" has the meaning set forth in the preamble.

1.1.57 "Extended Force Majeure Event" - has the meaning assigned in Section 16.6.1.

1.1.58 "Facility" - means the Santa Rosa Energy Center combined cycle electric plant, interconnected to the Florida Power & Light Company Transmission System and includes one General Electric 7FA.03 combustion turbine, a Nooter/Eriksen Heat Recovery Steam Generator, and a GE model SAXC+1 UE/UA steam turbine configured as a 1-on-1 combined cycle unit, and all auxiliary equipment and facilities installed on Seller's side of the Point of Interconnection and the Primary Gas Delivery Point at the Site necessary or used for the production, control, delivery or monitoring of electricity produced on the Site.

1.1.59 "Facility NOx Allowances" - has the meaning assigned in Section 12.3.1.

1.1.60 "Facility SO_2 Allowances" - has the meaning assigned in Section 12.3.1.

1.1.61 "FASB" - means the Financial Accounting Standards Board.

1.1.62 "Federal Power Act" - means the Federal Power Act, 16 U.S.C. § § 791a *et seq.* (1994), as such Act may be amended from time to time, and any successor statute of similar import.

1.1.63 "FERC" - means the Federal Energy Regulatory Commission or any Governmental Authority succeeding to the powers and functions thereof under the Federal Power Act.

1.1.64 "Finance Lease" - has the meaning as set forth in the ASC Topic 842, Leases, as issued and modified from time to time by FASB.

1.1.65 "Firm Transportation" - means the firm transportation service **REDACTED REDACTED REDACTED

Company Open Access Transmission Tariff and any successor in function thereto.

1.179C "Florida Power and Light Company Transmission System" - means the integrated high voltage electricity transmission systems of the Florida Power and Light operating companies, as modified or expanded from time-to-time, as well as any successor in function thereto.

1.1.67 "Force Majeure Event" - has the meaning assigned in Section 16.1.

1.1.68 "Force Majeure Remedy Plan" - has the meaning assigned in Section 16.6.1.

1.1.69 "Forced Derate" - means a time during which the generating capability of the Facility is reduced below the Designated Capacity for reasons other than a Force Majeure Event and which is not a Scheduled Outage or a Maintenance Outage, and excluding a Forced Outage.

1.1.70 "Forced Outage" - means a time during which the Facility is not capable of normal operations for reasons other than a Force Majeure Event and which is not a Scheduled Outage or a Maintenance Outage.

1.1.71 "GAAP" - means generally accepted accounting principles, as such may be modified from time to time.

1.1.72 "Gains" - has the meaning assigned in Section 17.3.3.

1.1.73 "Gas Day" - means a period of twenty-four (24) consecutive hours beginning and ending at 9:00 a.m. CPT.

1.1.74 "Gas Supply Plan" - has the meaning assigned in Section 12.1.1.

1.1.75 "Georgia Integrated Transmission System" - means the integrated transmission system in Georgia, which consists of electric transmission facilities (>40 kV) that are individually owned and maintained by participating utilities who jointly plan and operate through agreements among Georgia Transmission Corporation, Georgia Power Company, Municipal Electric Authority of Georgia (MEAG Power) and Dalton Utilities.

1.1.76 "GHG Cap" - means the GHG Rate times the quantity of fuel required in order to comply with Buyer's Scheduling Instructions.

1.1.77 "GHG Charges" - means any Taxes imposed on the Facility or Seller by a Governmental Authority under a New GHG Law for Greenhouse Gas emitted by and attributable to the Facility after the Delivery Commencement Date and prior to the end of the Term.

1.1.78 "GHG Credits" - means any instrument, credit, offset, allowance or similar right to emit Greenhouse Gas issued by a Governmental Authority in accordance with Legal Requirements or any revenues which are allocated to or received by any Person or generating facility associated with any GHG emissions or the avoidance of or reduction in the production of GHG emissions.

1.1.79 "GHG Rate" - means: (i) with respect to CO2, 118.86 lbs. of CO2 / MMBtu; and (ii) with respect to any other Greenhouse Gas, a rate established by Buyer that is equal to the average emissions rate for the applicable Greenhouse Gas from Buyer's own combined cycle electric generation facilities.

1.1.80 "Governmental Approvals" - means any and all licenses, permits, franchises, agreements, approvals, authorizations, consents, waivers, rights, exemptions, releases, variances, exceptions, or orders of or issued by, or filing with, or notice to, any Governmental Authority under Legal Requirements.

1.1.81 "Governmental Authority" - means any local, state, regional or federal administrative, legal, judicial or executive agency, court, commission, department or other such entity, but excluding any such agency, court, commission, department or other such entity acting in a capacity as lender, guarantor or mortgagee.

1.1.82 "GPSC" - means the Georgia Public Service Commission or any Governmental Authority succeeding to the powers and functions thereof.

1.1.83 "GPSC Certificate" - has the meaning assigned in Section 2.3.1.

1.1.84 "Greenhouse Gas" or "GHG" - means carbon dioxide (CO_2), methane (CH_4), nitrous oxide (N_20), sulfur hexafluoride (SF_6), hydrofluorocarbons (HFCs), perfluorocarbons (PFCs) and other gases or emissions classified as a greenhouse gas as contributing to the greenhouse effect.

1.1.85 "Grid Emergency" - has the meaning as that term is defined in the Seller's Interconnection Agreement.

1.1.86 "Guaranteed Heat Rates" - means the guaranteed heat rates set forth in **Appendix C**, Section D.

1.1.87 "Hot Gas Path Inspection" - means the hot gas path inspection as defined by the maintenance documents of the original equipment manufacturer.

1.1.88 "HRSG" - means heat recovery steam generator.

1.1.89 "Imbalance Charges" - has the meaning assigned in Section 12.2.5.

1.1.90 "Impasse Notice" - has the meaning assigned in Section 20.1.

1.1.91 "Indebtedness" - of any Person means all of the following without duplication: (a) obligations of such Person for borrowed money evidenced by bonds, debentures, notes, loan agreements or other similar instruments; (b) purchase money indebtedness of such Person constituting an obligation to pay the deferred purchase price of property or services, other than trade payables incurred in the ordinary course of business; (c) lease obligations of such Person which are capitalized on the balance sheet of such Person in accordance with GAAP; (d) liabilities of a second Person secured by any lien on any property of such first Person, whether or not such liabilities have been assumed by such first Person; (e) liabilities of such Person with respect to letters of credit or applications or reimbursement agreements therefor; (f) net obligations of such Person under any swap or hedging agreement; or (g) indebtedness of such Person owing under direct or indirect guarantees of indebtedness of any other Person or constituting obligations to purchase or acquire or to otherwise protect or insure a creditor against loss in respect of indebtedness of any other Person excluding endorsements of negotiable instruments for deposit or collection in the ordinary course of business.

1.1.92 "Indemnified Party" - has the meaning assigned in Section 15.1.

1.1.93 "Interconnection Agreement" - means that certain Interconnection Agreement entered into by and between Santa Rosa Energy, LLC and Gulf Power Company dated as of August 27, 2001, that provides for the construction and operation of the Interconnection Facilities and governs the interconnection and parallel operation of the Facility with the Florida Power & Light Company Transmission System.

1.1.94 "Interconnection Facilities" - means those facilities described in the Interconnection Agreement as facilities that must be installed or modified in order to enable the Facility to deliver the energy associated with the Contracted Capacity to meet Buyer's Schedules from the Facility to the Florida Power & Light Company Transmission System.

1.1.95 "Interest Rate" - means the interest per annum equal to the prime rate as published in *The Wall Street Journal*, or comparable successor publication, under "Money Rates," as applied on a daily basis and compounded quarterly.

1.1.96 "JAMS" - has the meaning assigned in Section 20.3.1.

1.1.97 "kV" - means kilovolt(s).

1.1.98 "kW" - means kilowatt(s).

1.1.99 "Legal Requirement" - means any law, code, statute, regulation, rule, ordinance, permit, judgment, injunction, order, Consent or other requirement of a Governmental Authority having jurisdiction over the matter in question that is valid and applicable to the matter in question at the time of the execution of this Agreement or any time thereafter during the Term.

1.1.100 "Letter of Credit" - means a standby letter of credit, substantially in the form attached hereto as **Appendix H** and which is issued by a U.S. commercial bank or the U.S. branch of a foreign bank with total assets of at least ten billion dollars ($10,000,000,000) having a general long-term senior unsecured debt rating of A minus or higher as rated by S&P, or A3 or higher as rated by Moody's, or A minus or higher as rated by Fitch.

1.1.101 "Losses" - has the meaning assigned in Section 17.3.3.

1.1.102 "Maintenance Outage" - means a planned interruption of a portion or all of the Facility's generation capability that: (i) has been coordinated in advance with Buyer with a mutually agreed start date, time and duration or to which Buyer has consented pursuant to Section 11.2.2; and (ii) is for the purpose of performing work on specific components of the Facility that would limit the power output of the Facility but should not, in the reasonable judgment of Seller, be postponed until the next Scheduled Outage.

1.1.103 "Maintenance Schedules" - has the meaning assigned in Section 11.2.1.

1.1.104 "Major Inspection" - means major inspection as defined by the maintenance documents of the original equipment manufacturer.

1.1.105 "Material Adverse Change" - means that Seller or, if Seller is providing Eligible Collateral in the form of a Seller Guaranty, that Seller Guarantor experiences any of the events described in clauses (a) or (b): (a) such Person is no longer Creditworthy; or (b) the maturity of any Indebtedness of such Person which in the aggregate exceeds one hundred fifty million dollars ($150,000,000.00) or five

percent (5%) of equity, whichever is less, is accelerated by the holder or holders thereof as a result of a default thereunder.

1.1.106 "Metering System" - means all meters, metering devices and related instruments used to measure and record electric energy and to determine the amount of such electric energy that is delivered to Buyer at the Point of Interconnection and for the other purposes set forth in Section 9.2.

1.1.107 "Minimum Capacity" - has the meaning assigned in **Appendix C**, Section I.B.

1.1.108 "MMBtu" - means one million British thermal units. One (1) MMBtu is equivalent to one (1) dekatherm.

1.1.109 "Month" - means a calendar month, commencing at the beginning of the first Day of such calendar month. "Monthly" has a meaning correlative to that of Month.

1.1.110 "Monthly Availability Adjustment" or "MAA" - has the meaning assigned in and is determined pursuant to **Appendix A**, Section C.

1.1.111 "Monthly Availability Factor" or "MAF" - has the meaning assigned in and is determined pursuant to Table A-4 in **Appendix A.**

1.1.112 "Monthly Availability Percentage" or "MAP" - has the meaning assigned in and is determined pursuant to **Appendix A**, Section C.

1.1.113 "Monthly Capacity Fee" or "MCF" - has the meaning assigned in and is determined pursuant to **Appendix A**, Section B.

1.1.114 "Monthly Capacity Payment" or "MCP" - means the amount to be paid by Buyer to Seller for Buyer's purchase of the Designated Capacity for a particular Month, as provided in Section 5.2 and determined pursuant to **Appendix A**, Section B.

1.1.115 "Monthly Energy Payment" or "MEP" - means the amount to be paid by Buyer to Seller for Buyer's purchase of energy and Ancillary Services for a particular Month, as provided in Section 5.3 and determined pursuant to **Appendix B,** Section A.

1.1.116 "Monthly Fuel Charge" or "MFC" - has the meaning assigned in **Appendix B,** Sections A and E.

1.1.117 "Monthly Invoice" - has the meaning assigned in Section 6.1.1.

1.1.118 "Monthly Startup Charge" or "MSC" - has the meaning assigned in **Appendix B**, Section C.

1.1.119 "Monthly Value Factor" or "MVF" - has the meaning assigned in Table A-3 in **Appendix A.**

1.1.120 "Moody's" - means Moody's Investors Service, Inc. or its successor.

1.1.121 "MVOM" - has the meaning assigned in **Appendix B**, Section B.

1.1.122 "MW" - means megawatt(s).

1.1.123 "MWh" - means megawatt-hour(s).

1.1.124 "Natural Gas" - means a mixture of hydrocarbon gasses that occurs with petroleum deposits, principally methane, together with varying quantities of ethane, propane, butane, and other gases, but excluding manufactured or artificial gas.

1.1.125 "NERC" - means the North American Electric Reliability Corporation, including any successor thereto and subdivisions thereof.

1.1.126 "New GHG Law" - means a Legal Requirement enacted after the Execution Date that imposes GHG Charges as a direct result of the generation of electric energy by the Facility.

1.1.127 "Nominal Capability" - means 215 MW.

1.1.128 "Non-Defaulting Party" - has the meaning assigned in Section 17.3.1.

1.1.129 "Notice of Dispute" - has the meaning assigned in Section 20.1.

1.1.130 "NOx Allowances" - means allowances required by any Governmental Authority or Consent for NOx Emissions.

1.1.131 "NOx Emissions" - means emissions of nitrogen oxides.

1.1.132 "OATI" - means Open Access Technology International, Inc.

1.1.133 "Operating Committee" - means the committee established pursuant to Section 11.7.

1.1.134 "Operating Procedures" - means those procedures developed by the Parties pursuant to Section 11.1.2.

1.1.135 "Operating Representatives" - means those individuals appointed by each of the Parties to the Operating Committee pursuant to Section 11.7.

1.1.136 "Operator Requested Schedule" - has the meaning assigned in Section 13.2.4.

1.1.137 "Party" or "Parties" - means either Buyer or Seller, or both, respectively.

1.1.138 "Party Appointed Arbitrators" - has the meaning assigned in Section 20.3.2.1.

1.1.139 "Performance Test" or "Performance Testing" - means a performance test conducted in accordance with the procedures set forth in **Appendix D**.

1.1.140 "Person" - means any natural person, corporation, limited liability company, general partnership, limited partnership, proprietorship, other business organization, trust, union, association, or Governmental Authority.

1.1.141 "Point of Interconnection" - means the interface between the Florida Power & Light Transmission System and the Facility's electrical facilities at the deadend structure immediately outside of the Facility's 230 kV switchyard.

1.1.142 "Primary Beneficiary" - has the meaning set forth in ASC Topic 810, Consolidation, as issued and modified from time to time by FASB.

1.1.143 "Primary Gas Delivery Point" - means the point of interconnection between the Facility and the Gulf South pipeline serving the Facility.

1.1.144 "Proposed Resolutions" - has the meaning assigned in Section 20.3.3.

1.1.145 "Prudent Industry Practices" - means, any of the practices, methods, standards and acts engaged in or approved by a significant portion of the independent power industry in the United States that, at a particular time, in the exercise of reasonable judgment in light of the facts known or that reasonably should have been known at the time a decision was made, could have been expected to accomplish the desired result consistent with good business practices, reliability, economy, safety and expedition. Prudent Industry Practices are not intended to be limited to the optimum practices, methods or acts to the exclusion of all others, but rather to be acceptable practices, methods and acts generally accepted in the United States, having due regard for, among other things, manufacturers' warranties, and applicable Legal Requirements.

1.1.146 "Qualified Operator" - means any Person that has, or is a Subsidiary of a Person that (either itself or through one or more Affiliates) has, at least three (3) years of experience operating one

or more combined-cycle natural gas fired power generation stations in the United States having an aggregate nameplate capacity in excess of 250 MW.

1.1.147 "Rating Agency" or "Rating Agencies" - means the rating entities of S&P, Moody's or Fitch. If any Rating Agency ceases to exist or publish ratings, such Rating Agency will be replaced under this Agreement with a nationally recognized rating agency mutually agreed upon by the Parties.

1.1.148 "Reference Conditions" – means: (i) during the Months of May through October, ninety-five degrees Fahrenheit (95°F), forty-five percent (45%) relative humidity, average barometric pressure at the site at the reference temperature and relative humidity, and the maximum reactive power obligation as specified in the Interconnection Agreement, and (ii) during the Months of November through April, forty-five degrees Fahrenheit (45°F), seventy-five percent (75%) relative humidity, average barometric pressure at the site at the reference temperature and relative humidity, and the maximum reactive power obligation as specified in the Interconnection Agreement.

1.1.149 "Representatives" - means, when used with respect to a Party, collectively or individually (as the context might indicate), such Party, its Affiliates and permitted successors and assigns, and the directors, officers, representatives, agents, contractors, subcontractors, and employees of each of them.

1.1.150 "Responding Party" - has the meaning assigned in Section 20.1.

1.1.151 "Rules" - has the meaning assigned in Section 20.3.1.

1.1.152 "S&P" - means Standard & Poor's Financial Services LLC, or its successor.

1.1.153 "Schedule," "Scheduled," "Scheduling" and "Scheduling Instructions" - mean instructions issued by Buyer from the Scheduling Center to Seller with respect to the scheduling of the production of electricity by the Facility, or the delivery of energy from an Alternate Resource if applicable under Section 5.1.4, in accordance with Article 13 and **Appendix D**.

1.1.154 "Scheduled Outage" - has the meaning assigned in Section 11.2.1.

1.1.155 "Scheduling Center" - means the scheduling center designated by Buyer from time to time in writing as being the primary control point for Scheduling Instructions and other notifications

provided pursuant to Article 13 and **Appendix D**, Section II. There may only be one Scheduling Center designated at any one time.

1.1.156 "Seasonal Performance Period" or "Season" - means one (1) of the following periods during each Annual Period: Summer (June through September); Fall (October and November); Winter (December, January and February); or Spring (March through May).

1.1.157 "Seller" - has the meaning assigned in the preamble.

1.1.158 "Seller Guarantor" - means a Person that, at the time of execution and delivery of its Seller Guaranty, is a direct or indirect owner of Seller, or is otherwise an entity acceptable to Buyer, and (a) is Creditworthy; and (b) has satisfactory and verifiable creditworthiness determined in Buyer's sole discretion.

1.1.159 "Seller Guaranty" - means a guaranty provided by the Seller Guarantor that is substantially in the form of the guaranty attached hereto as **Appendix I**.

1.1.160 "Seller Performance Security" - has the meaning assigned in Section 7.1.

1.1.161 "Seller Response Deadline" - has the meaning assigned in Section 18.2.6.

1.1.162 "Seller Response Notice" - has the meaning assigned in Section 18.2.6.

1.1.163 "SERC" - means the Southeastern Electric Reliability Council, including any successor thereto.

1.1.164 "Site" - means the land in Santa Rosa County, in the state of Florida, on which the Facility is located, as set forth in **Appendix G**.

1.1.165 "SO_2 Allowances" - means allowances required by any Governmental Authority or Consent for SO_2 Emissions.

1.1.166 "SO_2 Emissions" - means emissions of sulfur dioxide.

1.1.167 "Southern Balancing Authority Area" and "SBAA" - means the NERC and SERC recognized balancing authority area that includes the Transmission System.

1.1.168 "Southern Company Transmission System" - means the integrated high voltage electricity transmission systems of the electric utility operating companies of The Southern Company (as of the date of this Agreement, Alabama Power Company, Georgia Power Company, and Mississippi Power Company), as modified or expanded from time-to-time, as well as any successor in function thereto.

1.1.169 "Southern OATT" - means The Southern Companies Open Access Transmission Tariff and any successor in function thereto.

1.1.170 "Startup Energy" - means energy produced during startup when ramping to the Minimum Capacity.

1.1.171 "Startup Event" - has the meaning assigned in **Appendix B**.

1.1.172 "Station Service" - means energy that is used to serve the electrical requirements of the Facility and includes the transformer losses and line losses between the Facility and the Transmission System.

1.1.173 "Subsidiary" – means, as to any Person, a corporation, partnership, limited liability company or other entity of which shares of stock or other ownership interests having ordinary voting power (other than stock or such other ownership interests having such power only by reason of the happening of a contingency) to elect a majority of the board of directors or other managers, or similar governing body, of such corporation, partnership, limited liability company or other entity are at the time owned, or the management of which is otherwise controlled, directly or indirectly through one or more intermediaries, or both, by such Person.

1.1.174 "System Emergency" - means that the Scheduling Center has determined pursuant to its prevailing practices that conditions are expected to occur or have occurred that could jeopardize the ability to meet projected loads in the SBAA.

1.1.175 "Taxes" - means all taxes, fees, levies, licenses, or charges imposed by any Governmental Authority, other than taxes, levies, licenses, or charges based upon net income or net worth, together with any interest and penalties thereon.

1.1.176 "Technical Limits" - means the operational limits and constraints described in **Appendix C**, Section I.

1.1.177 "Term" - means the term of this Agreement specified in Section 2.1.

1.1.178 "Termination Payment" - has the meaning assigned in Section 17.3.2.

1.1.179 "Tested Reliable Capacity" - means the capability of the Facility at Reference Conditions to produce Energy as demonstrated pursuant to the Performance Test or as otherwise indicated in **Appendix A.**

1.1.180 "Third Arbitrator" - has the meaning assigned in Section 20.3.2.1.

1.1.181 "Threshold Amount" - has the meaning assigned in Section 18.2.4.

1.1.182 "Transmission Provider" - means the owner or operator of the Transmission System responsible for providing transmission service under the Southern OATT and the owner or operator of the Florida Power and Light Company Transmission System for providing transmission system under the Florida Power and Light Company OATT.

1.1.183 "Transmission System" - means the Southern Company Transmission System and the Georgia Integrated Transmission System.

1.1.184 "Unavailability Event" - means any single, continuous period during which the Facility or an Alternate Resource (designated pursuant to Section 5.1.4), is Unavailable to serve Buyer's Schedules, in whole or in part.

1.1.185 "Unavailable" or "Unavailability" - means the extent to which at all times following the Delivery Commencement Date the Facility or an Alternate Resource (designated pursuant to Section 5.1.4), as the case may be, is unable to deliver energy pursuant to a Schedule due to a Scheduled Outage, Maintenance Outage, Forced Outage, Forced Derate or a Force Majeure Event.

1.1.186 "Unplanned (Forced) Outage Hours" or "FOH" - means the hours during which the Facility experiences a Forced Outage and as further defined in **Appendix A**, Section C.1.

1.1.187 "Variable Interest" or "VI" - has the meaning as set forth in ASC Topic 810, Consolidation, as issued and modified from time to time by FASB.

1.1.188 "Variable Interest Entity" or "VIE" - has the meaning as set forth in ASC Topic 810, Consolidation, as issued and modified from time to time by FASB.

ARTICLE 2

TERM OF AGREEMENT

2.1 Term. This Agreement shall become effective upon satisfaction or waiver of the conditions

precedent set forth in Section 2.3 (such date, the "Effective Date") and shall remain in full force and effect through Hour Ending 2400, December 31, 2028.

2.2 Survival. All provisions of this Agreement that expressly or by implication come into or continue in force and effect following the expiration or termination of this Agreement shall remain in effect and be enforceable following such expiration or termination.

2.3 Conditions Precedent.

2.3.1 Filing Application for Certification with the GPSC. Buyer will use reasonable efforts to file for GPSC certification of this Agreement as soon as reasonably practicable after execution of this Agreement but no later than November 1, 2023, and to pursue and obtain a GPSC certificate (the "GPSC Certificate"). Seller agrees to assist and support Buyer, in a timely manner and to the extent reasonably requested by Buyer, in obtaining the GPSC Certificate.

2.3.2 Certificate Conditions. If: (i) the GPSC issues a GPSC Certificate that is subject to material qualifications or conditions that adversely affect Buyer; (ii) the GPSC has not approved this Agreement through the granting of a GPSC Certificate for the recovery in rates for the purchase of capacity and associated energy and Ancillary Services from the Facility; or (iii) the GPSC fails to issue a GPSC Certificate by the date required in GPSC Rule 515-3-4-.07(1)(e)(5), then Buyer may terminate this Agreement upon written notice to Seller. If Buyer terminates this Agreement under subpart (i) or (ii), then Buyer must give Seller notice of termination no later than 30 Days after the issuance of the Order either approving the GPSC Certificate with material qualifications or conditions, or denying the GPSC Certificate, or in the case of a termination under subpart (iii), within 30 days after the date required in GPSC Rule 515-3-4-.07(1)(e)(5). If, within 30 Days after the Order approving or denying the GPSC Certificate, Buyer appeals the issuance or denial of the GPSC Certificate to the GPSC or Fulton County Superior Court, then Buyer's right to terminate this Agreement will be extended until the earlier of (x) the date that is 80 Days after the Order approving or denying the GPSC Certificate and (y) July 31, 2024. Upon a termination pursuant to this Section 2.3.2, (i) neither Party will have any further liability to the other Party under this Agreement, and (ii) Buyer will promptly return to Seller any unused portion of the Performance Security.

2.3.3 Commercial Start Date. The Commercial Start Date shall have occurred.

2.3.4 Prior to the Delivery Commencement Date, Buyer obtains network integrated

transmission service and ancillary services under the Southern Company OATT necessary to transmit Delivered Energy purchased under this Agreement (less Florida Power & Light Company transmission losses) from the Commercial Start Date through December 31, 2028 from the point(s) of interconnection between the Florida Power & Light Company Transmission System and the Southern Transmission System to the Buyer's load without any material limitation or condition that is not acceptable to Buyer in Buyer's sole judgment.

ARTICLE 3

REPRESENTATIONS, WARRANTIES AND COVENANTS

3.1 Representations and Warranties of Seller. Seller hereby makes the following representations and warranties to Buyer as of the date of this Agreement:

3.1.1 Seller is a limited liability company, duly organized, validly existing and in good standing under the laws of the state of Delaware that is qualified to do business in Florida, is the sole owner of the Facility, and has the legal power and authority to own its properties, to carry on its business as now being conducted and to enter into this Agreement and to otherwise carry out the transactions contemplated hereby and perform and fulfill all covenants and obligations on Seller's part to be performed under and pursuant to this Agreement.

3.1.2 The execution, delivery and performance by Seller of this Agreement have been duly authorized by all necessary limited liability company action, and do not and will not require any consents or approvals of any Person other than those which have already been properly obtained.

3.1.3 The execution and delivery of this Agreement, the consummation of the transactions contemplated hereby and the fulfillment of and compliance with the provisions of this Agreement, do not and will not conflict with or constitute a breach of or a default under, any of the terms, conditions or provisions of any Legal Requirement, charter, bylaw, operating agreement or other formation document applicable to Seller or any organizational document of Seller, or any deed of trust, mortgage, loan agreement, other evidence of indebtedness or any other agreement or instrument to which Seller is a party or by which it or any of its property is bound.

3.1.4 This Agreement constitutes the legal, valid and binding obligations of Seller that are enforceable in accordance with their terms, except as such enforceability may be limited by bankruptcy, insolvency, reorganization or similar laws relating to or affecting the enforcement of creditors' rights generally or by general equitable principles, regardless of whether such enforceability is considered in a proceeding in equity or at law.

3.1.5 As of the date hereof there is no pending, or to the knowledge of Seller, threatened action or proceeding against Seller before any Governmental Authority that purports to affect the legality, validity or enforceability of this Agreement or that could reasonably be expected to have a material adverse effect on Seller's ability to perform its obligations under this Agreement.

3.1.6 Seller is not debarred, suspended, or proposed for debarment as a contractor or subcontractor to any department, agency or other division of the United States Government.

3.1.7 To the best of Seller's knowledge and belief, Buyer will not be required by any Legal Requirement or any accounting standard, including those implemented or administered by FASB, to consolidate Seller or any of its Affiliates or permitted assigns as a VIE in Buyer's or any of its Affiliates' financial statements.

3.1.8 There are no bankruptcy proceedings pending or being contemplated by Seller or, to Seller's knowledge, threatened against Seller.

3.2 Representations and Warranties of Buyer. Buyer hereby makes the following representations and warranties to Seller as of the date of this Agreement:

3.2.1 Buyer is a corporation, duly organized, validly existing and in good standing under the laws of the state of Georgia, that is qualified to do business in the state of Georgia and has the legal power and authority to own its properties, to carry on its business as now being conducted and to enter into this Agreement and carry out the transactions contemplated hereby and perform and fulfill all covenants and obligations on its part to be performed under and pursuant to this Agreement.

3.2.2 The execution, delivery and performance by Buyer of this Agreement have been duly authorized by all necessary corporate action, and do not and will not require any consent or approval of Buyer's board of directors or shareholders other than that which has already been obtained.

3.2.3 Subject to Section 2.3, the execution and delivery of this Agreement, the consummation of the transactions contemplated hereby and the fulfillment of and compliance with the provisions of this Agreement do not and will not conflict with any of the terms, conditions or provisions of any Legal Requirements applicable to Buyer, or of any partnership agreement, deed of trust, mortgage, loan agreement, other evidence of indebtedness or any other agreement or instrument to which Buyer is a party or by which it or any of its property is bound, or result in a breach of or a default under any of the foregoing.

3.2.4 This Agreement constitutes the legal, valid, and binding obligation of Buyer that is enforceable in accordance with its terms, except as such enforceability may be limited by bankruptcy, insolvency, reorganization or similar laws relating to or affecting the enforcement of creditors' rights generally or by general equitable principles, regardless of whether such enforceability is considered in a proceeding in equity or at law.

3.2.5 There is no pending or, to the knowledge of Buyer, threatened action or proceeding affecting Buyer before any Governmental Authority which purports to materially adversely affect the legality, validity, or enforceability of this Agreement or that reasonably could be expected to have a material adverse effect on Buyer's ability to perform its obligations under this Agreement.

3.2.6 Buyer is Creditworthy and there are no bankruptcy proceedings pending or being contemplated by it or, to its knowledge, threatened against it.

3.3 Seller Covenants. Seller hereby covenants and agrees that throughout the Term:

3.3.1 No modifications to, or expansion of, the Facility that would have a material adverse effect on Buyer's rights or obligations under this Agreement will occur without the prior written consent of Buyer, which consent shall not be unreasonably withheld, conditioned or delayed.

3.3.2 Seller will not convey, sell, lease, transfer or otherwise dispose of all or substantially all of its business or assets, whether now owned or hereafter acquired, to the extent that such conveyance, sale, lease, transfer or other disposition would have a material adverse effect on Buyer's rights or obligations under this Agreement without the prior written consent of Buyer, which consent shall not be unreasonably withheld, conditioned or delayed.

3.3.3 Buyer will not be required by any Legal Requirement or any accounting standard, including but not limited to those implemented or administered by the FASB, to consolidate Seller or any of its Affiliates or permitted assigns as a VIE in Buyer's or any of its Affiliates' financial statements. Seller covenants to promptly notify Buyer following any determination made by Seller or its independent auditor that Seller constitutes a VIE for which Buyer is the Primary Beneficiary as a result of this Agreement, considered individually or together with any other power purchase agreements between Seller and Buyer. Seller will provide to Buyer a VIE certification form in the form of **Appendix L** signed by the chief financial officer or another duly authorized officer of Seller (i) within five (5) days of execution of this Agreement, and (ii) within five (5) days of assignment or amendment of this Agreement by the Parties. Seller will also provide Buyer a Finance Lease certification in the form of **Appendix M** signed by chief financial officer or another duly authorized officer of Seller within five (5) Days after the execution of this Agreement and thereafter at any time this Agreement is amended or assigned by the Parties. Seller covenants to promptly notify Buyer following any determination made by Seller or its independent auditor that Seller must be partially or fully deconsolidated from the books of Seller or Seller's parent, as the case may be. If (i) Buyer is required by any Legal Requirement or any accounting standard, including but not limited to those implemented or administered by FASB, to consolidate Seller or any of its Affiliates or permitted assigns as a VIE in Buyer's or any of its Affiliates' financial statements or (ii) Seller is in breach of any of its covenants in respect of this Section 3.3.3, then Buyer shall promptly provide notice to Seller. Seller shall have a period of thirty (30) Days in which to remedy such consolidation or breach (unless such remedy is not capable of being effected within such thirty (30) Day period, in which case Seller shall have an additional thirty (30) Day period outlining steps to assure Buyer that the failure will be remedied, which remedial plan shall be subject to Buyer's approval, such approval not to be unreasonably withheld by Buyer, but in no event shall the total remedial period exceed one hundred eighty (180) Days). Buyer shall be required to cooperate with Seller during the remedial period and shall take commercially reasonable actions necessary to bring about a determination by Buyer and its independent auditors that Seller does not constitute a VIE as a result of this Agreement. If Seller is not able to remedy such consolidation or breach within such thirty (30) Day period, as extended, Buyer shall have the option to terminate this Agreement on thirty (30) Days' notice to Seller and neither Party shall have any further liability to the other Party under this Agreement (except

liabilities arising prior to the date of such termination), and (ii) Buyer will promptly return to Seller any unused portion of the Seller Performance Security.

3.3.4 Except as may be allowed pursuant to Sections 3.3.2, 19.2, or any other provisions of this Agreement, Seller will maintain the legal right to and will possess and operate the Facility and deliver the capacity, energy, and Ancillary Services of the Facility to Buyer in accordance with the provisions of this Agreement.

3.3.5 Commencing on the Delivery Commencement Date and continuing until the end of the Term, Seller or Seller's agent shall make available for Buyer's use its firm point-to-point transmission service in the OATI system per the Florida Power and Light Company OATT in sufficient capacity to transmit Delivered Energy (up to the full output of the Facility) to the point(s) of interconnection between the Florida Power and Light Company Transmission System and the Southern Transmission System. Buyer and Seller shall include the administration of Seller's rights in respect of such firm point-to-point transmission service in the Operating Procedures.

3.4 Buyer Covenants. Buyer hereby covenants and agrees that:

3.4.1 Buyer shall throughout the Term, at the request of Seller, but only to the extent permissible under the Southern OATT, designate any Alternate Resource as a secondary network resource (or similar designation) for the period during which such Alternate Resource is used to provide Buyer with energy pursuant to this Agreement.

3.4.2 In connection with Buyer obtaining the network integrated transmission service and ancillary services under the Southern Company OATT in accordance with Section 2.3.4, Buyer shall (i) use commercially best efforts to obtain such services on or prior to the Commercial Start Date, and (ii) each Month following the Execution Date until such services are obtained, provide monthly written updates to Seller on the status of obtaining such services, including all reports, information and data as Seller may reasonably request.

ARTICLE 4

REGULATORY APPROVALS; COMPLIANCE WITH LAWS, RULES AND REGULATIONS; TAXES

4.1 Preservation of Terms.

4.1.1 Each Party agrees that, subject to Section 4.2, except with the prior written consent of the other Party, it will not institute or voluntarily cooperate in the institution or conduct of any claim, action or proceeding before FERC under Section 205, Section 206 or any other portion of the Federal Power Act, or any other Governmental Authority under any provision of federal law or state or local law or any other Legal Requirement which claim, action or proceeding is intended for the purpose of, or could reasonably be expected to have the effect of, changing the terms of this Agreement then in effect. Without limiting the foregoing, but subject to the terms of this Agreement, the Parties agree that the rates for service specified herein shall remain in effect for the Term and shall not be subject to change through application to FERC pursuant to the provisions of Section 205 or 206 of the Federal Power Act, or to any other Governmental Authority under any provision of federal law or Georgia state or local law or any other Legal Requirement, absent written agreement of the Parties.

4.1.2 In any proceeding before FERC involving this Agreement, the Parties shall request that FERC review any and all aspects of this Agreement under the "public interest" application of the "just and reasonable" standard of review in United Gas Pipe Line Co. v. Mobile Gas Service Corp., 350 U.S. 332 (1956) and Federal Power Commission v. Sierra Pacific Power Co., 350 U.S. 348 (1956), and clarified by NRG Power Marketing LLC v. Maine Public Utility Commission, 130 S. Ct. 693 (2010).

4.2 Other Approvals. Each Party shall diligently seek to obtain, maintain, pursue, or cause to be pursued, comply with and, as necessary, renew and modify from time to time any and all other Consents, required to be possessed by such Party, in a manner that is reasonably expected to enable such Party to perform its obligations under this Agreement. Each Party agrees to assist and support the other Party, in a timely manner and to the extent reasonably requested by either Party, in obtaining such Consents. Upon request, each Party shall provide a copy of such Consents to the requesting Party.

4.3 Revocation, Qualifications or Conditions. Notwithstanding the provisions of Clause 2.3.2 (Certificate Conditions), if at any time during the Term the GPSC revokes or issues an amended GPSC Certificate that imposes material qualifications or conditions that adversely affect Buyer, and unless Buyer and Seller agree to an amendment in accordance with this Agreement, Buyer will have the right to terminate this Agreement on notice to Seller if such material qualifications or conditions are not acceptable to Buyer; provided, however, that any such termination will not take effect until the later of (i) the date that is 180 days

following such notice of Buyer's election to terminate this Agreement in accordance with this Section 4.3, and (ii) July 1, 2027. Within 15 Days after Buyer's receipt of an amended GPSC Certificate, Buyer will provide Seller with written notice of whether such amended GPSC Certificate is subject to material qualifications or conditions and, if so, whether Buyer elects to terminate this Agreement. If Buyer fails to provide such notice within such 15 Day period, the Amended Commission Certificate will be deemed to be acceptable to Buyer. Upon a termination pursuant to this Section 4.3, (i) neither Party will have any further liability to the other Party under this Agreement (except for any liabilities arising prior to the date of such termination), and (ii) Buyer will promptly return to Seller any unused portion of the Seller Performance Security.

4.4 Taxes.

4.4.1 Subject to Section 18.1, Seller shall pay, or cause to be paid, all Taxes on or with respect to: (i) the Facility, including ownership, leasing, financing, operation, and maintenance; (ii) the production and delivery of energy and Ancillary Services to be provided to Buyer arising, in the case of energy, prior to the time of Seller's delivery of such energy to Buyer at the Point of Interconnection, or, in the case of Ancillary Services, prior to the time such Ancillary Services are made available to Buyer; and (iii) Seller's conversion of Natural Gas into electricity after delivery by Buyer and receipt by Seller of Natural Gas at the Primary Gas Delivery Point; provided, however, that nothing contained in this Section 4.4.1 shall be construed to affect the applicability of Section 18.1 to GHG Charges under any New GHG Law.

4.4.2 Buyer shall pay or cause to be paid all Taxes on or with respect to: (i) energy received by Buyer arising at and after the time such energy is delivered by Seller to the Point of Interconnection , (ii) Ancillary Services received by Buyer arising at and after the time such Ancillary Services are made available to Buyer , and (iii) Natural Gas received and possessed by Buyer at and prior to the time of delivery of such Natural Gas by Buyer to Seller at the Primary Gas Delivery Point. Such Taxes shall include such sales, use, excise or other similar Taxes on the sale to Buyer and purchase from Seller of capacity, energy, and Ancillary Services pursuant to this Agreement. Buyer shall be responsible for all Taxes arising out of the transfer and delivery by Buyer and receipt by Seller of Natural Gas at the Primary Gas Delivery Point, and Seller shall be responsible for any new Taxes that may arise after the date of execution of this Agreement concerning the conversion of Natural Gas into energy; provided, however,

that nothing contained in this Section 4.4.2 shall be construed to affect the applicability of Section 18.1 to GHG Charges under any New GHG Law.

4.4.3 Each Party shall use reasonable efforts to implement and administer the provisions of this Agreement in accordance with the intent of the Parties to minimize Taxes so long as neither Party is materially adversely affected by such efforts.

4.4.4 In the event Seller is required by law or regulation to remit or pay Taxes that are Buyer's responsibility hereunder, Seller may include such Taxes in the next Monthly Invoice and Buyer shall remit payment thereof in accordance with Article 6. Conversely, if Buyer is required by law or regulation to remit or pay Taxes that are Seller's responsibility hereunder, Buyer may deduct the amount of any such Taxes from the sums otherwise due to Seller under this Agreement. Any refunds associated with such Taxes will be handled in the same manner. Nothing herein shall obligate or cause a Party to pay or be liable to pay any Taxes from which it is exempt under applicable Legal Requirements.

ARTICLE 5

SALE AND DELIVERY OF CAPACITY AND ENERGY

5.1 Agreement to Sell and Purchase.

5.1.1 At all times during the Term, but subject to the terms of this Agreement, Seller agrees to sell to Buyer the entire electrical capability of the Facility, net of Station Service, as, when and to the extent Buyer Schedules such electrical capability, and all Ancillary Services. Subject to the terms of this Agreement, Buyer agrees to purchase from Seller such electrical output of the Facility, pursuant to Buyer's Scheduling Instructions, and the Designated Capacity associated with the Facility after the Delivery Commencement Date. For the avoidance of doubt, the delivery of energy to the Point of Interconnection includes the transfer to Buyer of all Ancillary Services associated with such energy. The Monthly Capacity Payment and the Monthly Energy Payments are the exclusive compensation owed to Seller for capacity, energy and Ancillary Services under this Agreement.

5.1.2 Seller is responsible for all Station Service at Seller's expense.

5.1.3 Except as otherwise provided in Section 5.1.4 with respect to delivery of capacity and energy at an Alternate Delivery Point, Seller shall deliver capacity and energy from the Facility to Buyer

at the Point of Interconnection; provided, that the Parties agree that pursuant to Attachment V of the Southern OATT the Facility has been grandfathered access directly to the Transmission System with no additional cost for transmission service required to deliver Energy from the Point of Interconnection to the Transmission System. The risk of loss of energy shall pass from Seller to Buyer at the Point of Interconnection. Seller shall be responsible for providing generator balancing services with respect to the Florida Power and Light Company Balancing Authority Area and the Florida Power and Light Company OATT necessary for the receipt of energy pursuant to Buyer's Schedules and for any costs thereof. To the extent that electrical imbalance charges are caused by the action or inaction of a Party or such Party's Affiliates, contractors or subcontractors during the Delivery Period, such Party shall be responsible for, and pay or, to the extent the other Party is charged for same, reimburse the other Party for all electric imbalance charges. Notwithstanding the foregoing, the Parties shall reasonably cooperate with each other to avoid or mitigate electric imbalance charges.

5.1.4 Unavailability.

5.1.4.1 Following the Delivery Commencement Date, if the Facility is Unavailable, Seller shall have the option to elect to substitute physical Alternate Delivery from an Alternate Resource at an Alternate Delivery Point pursuant to Sections 5.1.4.2 and 5.1.4.3 in order to meet Buyer's Schedules (subject to the other provisions of this Agreement); provided, however, that Seller shall only be permitted to utilize an Alternate Resource to provide that portion of Scheduled energy that cannot be provided from the Facility due to such Unavailability Event.

5.1.4.2 If Seller elects to provide energy from an Alternate Resource, it shall, to the extent that the designated Alternate Resource(s) is Available, provide Buyer with a uniform quantity of energy in each hour that Buyer Schedules at least that quantity of energy. The hours (or equivalent hours) of delivery of energy from an Alternate Resource shall be incorporated as Alternate Resource Delivery Hours in the Monthly Availability Percentage calculations pursuant to **Appendix A**, Section C, and such failure to deliver from the Facility in the Alternate Resource Delivery Hours shall not be treated as Unavailability. Buyer shall be entitled to deduct from any Monthly Capacity Payment or Monthly Energy Payment, as the case may be, the amount of the incremental additional costs incurred by Buyer due to system losses as a result of Seller's delivery of Scheduled energy from an Alternate Resource, as compared

to the losses that Buyer would have incurred if such Scheduled energy were delivered from the Facility. Buyer shall determine the amount of incremental additional energy losses in a manner consistent with the methodology utilized by Buyer in applying loss penalties in its system dispatch; provided, however, such methodology shall not treat Seller's Alternate Resource in a materially different manner from Buyer's other generating resources. The Operating Representatives shall further develop Operating Procedures to calculate and bill Seller for such losses consistent with this Section 5.1.4.2.

5.1.4.3 In order to exercise its right to deliver energy from an Alternate Resource under Section 5.1.4.1 during a given Day, Seller must provide Buyer with advance notice in a manner agreed upon by the Operating Committee by no later than 7:00 a.m. CPT of the Business Day immediately prior to such Day of delivery, which notice shall specify the Alternate Resource and Alternate Delivery Point. Seller shall provide any other information that Buyer requires in order for Buyer to request firm network transmission service for such energy. Seller may propose to utilize only one (1) Alternate Delivery Point and only one (1) Alternate Resource for a given Day. Once Seller provides a notice of Alternate Delivery, Seller shall adhere to and shall not withdraw such Alternate Delivery without Buyer's written consent. For the avoidance of doubt, any failure to deliver energy pursuant to Buyer's Schedules from a designated Alternate Resource shall reduce the calculated Availability performance pursuant to **Appendix A**, Section C.

5.1.4.4 Following the Delivery Commencement Date, if the Facility is Unavailable as a result of a Force Majeure Event, in lieu of the suspension of Monthly Capacity Payments to the extent provided in Section 16.3, Seller shall have the option to elect Alternate Delivery in accordance with Section 5.1.4.3.

5.1.5 Notwithstanding the designation by Seller of the Designated Capacity pursuant to **Appendix A**, Buyer shall be entitled to Schedule and receive, and if Scheduled by Buyer, Seller shall be obligated to deliver, up to the entire energy output that the Facility is capable of producing when operated and all Ancillary Services from the Facility, subject to the Technical Limits and Scheduling procedures set forth in **Appendix C**.

5.1.6 During the Term, Seller shall not sell any of the capacity, energy or Ancillary Services associated with the Facility to any other Person, including the sale of any energy not Scheduled by Buyer.

5.1.7 Capacity Shortfall.

5.1.7.1 Buyer may declare a "Capacity Shortfall" if, during a Seasonal Performance Period, the Facility is Scheduled to operate at its Designated Capacity for any period of thirty (30) consecutive Days and the average actual Energy output of the Facility for such period of thirty (30) consecutive Days, adjusted to Reference Conditions, excluding ramping, is less than the Designated Capacity. However, the calculation of a Capacity Shortfall shall not include any reduction in output of the Facility to the extent caused by a Force Majeure Event, a Forced Derate, or a Forced Outage, in each case which has been properly declared by Seller pursuant to the terms of this Agreement, or to the extent due to a Transmission System outage.

5.1.7.2 When Buyer declares a Capacity Shortfall, Operating Representatives from both Parties shall convene, within ten (10) Business Days of such declaration, in order to review the data used by Buyer to support such Capacity Shortfall declaration. Actual hourly generation data from the Facility and the associated actual hourly ambient conditions (i.e., temperature and humidity) as measured at the Facility will be used by Buyer to determine the hourly output of the Facility, as adjusted to Reference Conditions, for any Capacity Shortfall declaration. Upon the completion of such review, Buyer, in its sole discretion, may elect to reduce the Designated Capacity by the Capacity Shortfall for the period of thirty (30) consecutive Days that triggered the Capacity Shortfall and for the remainder of the Annual Period, and such reduction would apply to successive Annual Periods, subject to any subsequent Capacity Shortfall, unless and until such time that Seller conducts a Performance Test pursuant to **Appendix D** and establishes a different Designated Capacity in accordance with **Appendix A**.

5.1.8 If Seller disputes Buyer's Capacity Shortfall declaration, then the matter shall be resolved pursuant to the provisions of Article 20. If Buyer elects to reduce the Designated Capacity pursuant to this Section 5.1.7.2, Buyer shall provide to Seller written notice of the reduction in Designated Capacity and its effective date.

5.2 Calculation of Monthly Capacity Payments. Subject to the terms of this Agreement, Buyer

shall pay Seller a Monthly Capacity Payment calculated in accordance with **Appendix A**, Section B.

5.3 Calculation of Monthly Energy Payments. Subject to the terms of this Agreement, Buyer shall pay Seller a Monthly Energy Payment calculated in accordance with **Appendix B**, Section A. For the avoidance of doubt, the Monthly Energy Payment includes all compensation owed to Seller for Ancillary Services associated with energy delivered to the Point of Interconnection.

ARTICLE 6

BILLING AND COLLECTIONS

6.1 Capacity and Energy Billing and Payment.

6.1.1 Subject to the provisions of Section 6.2, by the tenth (10^{th}) Day of each Month after the satisfaction of the conditions precedent in Section 2.3, Seller shall send Buyer an invoice stating the Monthly Capacity Payment, the Monthly Energy Payment, and, if applicable, any Monthly Availability Adjustment for the immediately preceding Month (or cumulative Months of a Season) ("Monthly Invoice"). Such invoice shall also specify any other payments required to be made by either Party pursuant to this Agreement, and with respect to payments to be paid by Seller, such payments shall be netted against payments due to Seller by Buyer.

6.1.2 All Monthly Invoices shall be due and payable by Buyer on or before the tenth (10^{th}) Day after Buyer's receipt of such invoice. If such tenth (10^{th}) Day is not a Business Day, then payment shall be due on the next succeeding Business Day. Subject to the provisions of Section 6.2, Buyer shall make payment to Seller in accordance with such invoices on or before the date due in immediately available funds, through wire transfer of funds to an account designated by Seller, or other means acceptable to Seller. Interest on unpaid amounts shall accrue from the date such payments were due at a rate equal to the Interest Rate. Each Monthly Invoice shall contain a statement explaining in reasonable detail how such invoice was calculated pursuant to Sections 5.2 and 5.3.

6.2 Billing Disputes and Final Accounting.

6.2.1 If Buyer questions or contests the amount or propriety of any payment claimed by Seller to be due pursuant to this Agreement, Buyer shall make payment to Seller of amounts not in dispute, but may withhold amounts disputed in good faith until after the settlement of such question or contest in

accordance with this Section 6.2 (provided that, for the avoidance of doubt, if such disputed amounts are determined to be due hereunder following such dispute, interest shall accrue on such amounts from the day the same were originally due pursuant to Section 6.3).

6.2.2 In the event Buyer questions or contests the correctness of any charge or credit, Buyer shall provide Seller with written notice of such amount and the basis for Buyer's question or contest accompanied by information supporting such question or contest in reasonable detail. Seller shall promptly review the questioned charge or credit and, if applicable, shall notify Buyer of any error in Seller's determination of amounts owed by Buyer and issue an amended invoice in the amount of any payment that Buyer is required to make in respect of such re-determination. If Buyer disputes in good faith Seller's amended invoice amount, then the matter shall be resolved pursuant to the provisions of Article 20 applicable to billing disputes. To the extent Seller disagrees with Buyer's basis for questioning the original invoice, Seller shall provide a written explanation of its position.

6.2.3 Seller shall have until the end of one (1) year after the date of delivery of energy under this Agreement to correct any invoice for payment due for such energy and associated capacity and deliver a corrected invoice to Buyer. Buyer shall have until the end of one (1) year after its receipt of any invoice to question or contest the correctness of any charge or credit made to Buyer on such invoice. If within such one (1) year period, Buyer has made payment under an invoice and thereafter questions or contests the correctness thereof, Seller shall not be required to refund any payment received from Buyer until such time as it is finally determined that Seller's invoice was in error.

6.3 Interest. If either Party does not make a payment required by this Agreement when due, then interest at the Interest Rate from the date such overdue payment was due until such overdue payment, together with interest, is paid shall be added to the due payment. If either Party makes a payment pursuant to an invoice that is later determined to have been incorrect, then interest at the Interest Rate from the date such overpayment was made shall be added to the overpayment until such overpayment, together with interest, is refunded to such Party. Remittance received by mail, if mail is a means of payment acceptable to a Party owed such payment, will be accepted without interest charges if such payment is postmarked on or before the due date. If the due date of any payment falls on a Day other than a Business Day, the next succeeding Business Day shall be the last Day on which payment can be postmarked without interest

charges being assessed. Notwithstanding this Section 6.3, no interest shall be paid with respect to any Monthly Availability Adjustment except to the extent that such Monthly Availability Adjustment was not correctly calculated and/or invoiced in accordance with this Agreement.

6.4 Billing and Payment Records. Each Party will, until the end of one (1) year after its receipt of any invoice, make available to the other Party, and each Party may audit, such books and records of the other Party as are necessary for such Party to verify the calculation of the Monthly Capacity Payments, the Monthly Energy Payments, and any Monthly Availability Adjustment, and any other invoice, charge or payment demand made in connection with this Agreement.

ARTICLE 7

PERFORMANCE SECURITY

7.1 Seller Performance Security. On or before the Delivery Commencement Date, Seller shall deliver Eligible Collateral to Buyer in an amount equal to the Eligible Collateral Amount (the "Seller Performance Security"). The Seller Performance Security shall be maintained throughout the Term. If any portion of the Eligible Collateral that Buyer is then holding is in the form of a Seller Guaranty and a Material Adverse Change occurs in respect of Seller Guarantor, then within three (3) Business Days, Seller shall deliver to Buyer replacement Eligible Collateral to replace such Seller Guaranty, which replacement Eligible Collateral shall be in a form other than a Seller Guaranty.

7.2 [Reserved]

7.3 Replacement Collateral; Substituted Collateral; Release of Collateral.

7.3.1 Replacement Collateral. To the extent that any replacement of Seller Performance Security is required to maintain compliance with Section 7.1, Seller shall deliver same to Buyer no later than ninety (90) Days prior to the date when the existing Eligible Collateral will expire (except where the expiration date is the last Day of the Term). In the event of a failure to comply with the preceding sentence, Buyer shall be entitled, without limitation to its other remedies under this Agreement or at law, to (i) draw the full amount on the existing Eligible Collateral prior to the expiration date thereof and (ii) take such further action to protect its interests pursuant to this Agreement. Upon receipt of any replacement Eligible Collateral, and provided that Seller remains in compliance with this Article 7, Buyer shall not draw upon the

existing Eligible Collateral, for which such replacement is being made, solely because such existing Eligible Collateral is about to expire.

7.3.2 Release of Collateral; Substituted Collateral. Upon replacement of the Seller Performance Security pursuant to Section 7.3.1, Buyer shall promptly release the Eligible Collateral that is being replaced back to Seller. The choice of any Eligible Collateral provided by Seller may be selected from time to time by Seller, and upon receipt and acceptance of substitute Eligible Collateral, Buyer shall promptly release such Eligible Collateral for which substitution is being made in an amount equal to that which is being substituted. Following any expiration or termination of this Agreement, the Parties shall mutually agree to a final settlement of all obligations under this Agreement, which such period shall not exceed fifteen (15) days from such termination date, and after such settlement, any remaining Eligible Collateral posted by Seller that has not been drawn upon by Buyer pursuant to its rights under this Agreement shall be returned to Seller. Any dispute between the Parties regarding such final settlement shall be resolved according to the applicable procedures set forth in Article 20, and any remaining Eligible Collateral posted by Seller shall not be returned to Seller until the resolution of such dispute.

7.4 Draws; Replenishment. In addition to the draws permitted by Section 7.3.1, Buyer may draw upon the Eligible Collateral provided by Seller to recover any damages to which Buyer is entitled under this Agreement (including damages following the occurrence of an Event of Default by Seller) or any other unpaid amounts owed by Seller under this Agreement, damages arising from an Event of Default by Seller, and termination damages arising from termination of this Agreement by Buyer for an Event of Default by Seller. In the event of a draw on the Eligible Collateral, then, Seller shall have no obligation to replenish the Eligible Collateral.

7.5 Reporting. Seller shall promptly notify Buyer of any circumstance that results in Seller's failure to be in compliance with the Seller Performance Security requirements of this Article 7. From time to time, at Buyer's written request, Seller shall provide Buyer with such evidence as Buyer may reasonably request to demonstrate that Seller and any Seller Guarantor, Seller Guaranty, Letter of Credit or Security Account is in full compliance with this Agreement.

7.6 Delivery of Eligible Collateral for Performance Security. Seller will provide to Buyer Eligible Collateral to meet any of the Performance Security requirements under this Agreement by delivering, as

applicable, cash wired to the Buyer Security Account, or Letter of Credit or Seller Guaranty to the following address:

Assistant Treasurer
Georgia Power Company
c/o Southern Company Services
BIN SC1407
30 Ivan Allen Jr. Blvd.
Atlanta, Georgia 30308

ARTICLE 8

RESERVED

ARTICLE 9

INTERCONNECTION AND METERING

9.1 Interconnection. The Interconnection Agreement shall be maintained throughout the Term of this Agreement. Seller shall promptly provide a copy of, and any amendments to, such Interconnection Agreement to Buyer in accordance with the notice provisions of Section 21.4. Buyer shall not be responsible under this Agreement for any costs and expenses (including overheads) incurred in connection with the design, construction, installation and maintenance of the Interconnection Facilities. Seller is responsible for determining all transmission-related rules, practices and policies with which it must comply.

9.2 Meters.

9.2.1 Seller shall ensure the Metering System is designed, located, constructed, installed, owned, operated and maintained in accordance with the Interconnection Agreement and Prudent Industry Practices in order to measure and record the amount of energy delivered from the Facility to the Point of Interconnection, to calculate the Facility capacity, and to measure the availability of the Facility in meeting Buyer's Schedules. The meters shall be of a mutually acceptable accuracy range and type. None of Seller, Seller's Affiliates or the employees, subcontractors or contractors of any of them shall make adjustments to the Metering System without the written consent of Buyer. Buyer may, at its own cost, install additional meters or other such facilities, equipment or devices on Buyer's side of the Point of Interconnection as Buyer deems necessary or appropriate to monitor the measurements of the Metering

System; provided, however, that in all cases Seller will be entitled to base its invoiced amounts solely by reference to its own Metering System. Buyer shall reasonably establish the telemetering equipment that is necessary to coordinate the Facility with the Scheduling Center and Seller shall, at its sole cost, install or cause the installation of such telemetering equipment. The telemetered data shall be delivered by Seller to the electrical switchyard of the Facility.

9.2.2 Seller shall inspect and test all meters at such times as will conform to Prudent Industry Practices, but not less often than once biennially. Seller shall be responsible for all costs and expenses incurred in connection with such inspections or tests.

9.2.3 If the Metering System fails to register, or if the measurement made by a metering device is found upon testing to vary by more than one-half percent (0.5%) from the measurement made by the standard meter used in the test, an adjustment shall be made correcting all measurements of energy made by the Metering System during: (i) the actual period when inaccurate measurements were made by the Metering System, if that period can be determined to the mutual satisfaction of the Parties; or (ii) if such actual period cannot be determined to the mutual satisfaction of the Parties, the second half of the period from the date of the last test of the Metering System to the date such failure is discovered or such test is made ("Adjustment Period"). If the Parties are unable to agree on the amount of the adjustment to be applied to the Adjustment Period, the amount of the adjustment shall be determined: (i) by correcting the error if the percentage of error is ascertainable by calibration, tests or mathematical calculation; or (ii) if not so ascertainable, by estimating on the basis of deliveries made under similar conditions during the period since the last test. Within thirty (30) Days after the determination of the amount of any adjustment, Buyer shall pay Seller any additional amounts then due for deliveries of energy or Designated Capacity during the Adjustment Period or Buyer shall be entitled to a credit against any subsequent payments for energy or Designated Capacity, as the case may be.

9.2.4 Buyer and its representatives shall be entitled to be present at any test, inspection, maintenance, adjustments and replacement of any part of the Metering System relating to obligations under this Agreement.

9.3 Reserved.

9.4 Loss Factor Adjustment. If, and to the extent, the Metering System is not measuring

deliveries of energy physically at the Point of Interconnection, the metered amount of energy shall be adjusted for losses to or from the Point of Interconnection by a loss factor determined by Buyer, in accordance with Prudent Industry Practices. Seller will be provided with a copy of any study or analysis prepared by Buyer in determining such loss factor.

ARTICLE 10

DESIGNATED CAPACITY; CAPACITY TESTS

10.1 Tested Reliable Capacity and Designated Capacity. The Tested Reliable Capacity and Declared Capacity Value shall be established in accordance with **Appendix A**. Performance Tests of the Facility shall be conducted pursuant to **Appendix D.** Upon completion by Seller of any Performance Test, Seller shall promptly provide to Buyer a complete written report, in accordance with **Appendix D**, of such Performance Test, certified by a responsible officer of Seller, for Buyer's review and verification. Following the Delivery Commencement Date, Seller shall cooperate with Buyer's request for information concerning the performance of the Facility that Buyer may reasonably request from time to time.

10.2 Disputes Concerning Performance Tests. In the event the Parties disagree with respect to the Performance Test results, the dispute shall be resolved pursuant to the provisions of Article 20 applicable to Performance Test results. If such dispute is not resolved by the first Day of any Annual Period, the Tested Reliable Capacity and Designated Capacity in effect for such Annual Period may not exceed the Tested Reliable Capacity and Designated Capacity established under **Appendix A** by the most recent undisputed Performance Test (or, if no Performance Test has yet to be undertaken, those applicable to the first Annual Period), subject to the outcome of this dispute resolution process. Following the resolution of the dispute, an adjustment shall be made to all Monthly Capacity Payments made with respect to such Annual Period to account for any difference between the new Tested Capacity Value and Designated Capacity and the preceding Tested Reliable Capacity and Designated Capacity.

ARTICLE 11

OPERATION AND MAINTENANCE

11.1 Operation and Maintenance.

11.1.1 Seller shall manage, control, operate and maintain all parts of the Facility in a manner consistent with Prudent Industry Practices, taking into account Buyer's right to Schedule the Facility, and in accordance with applicable planning standards and operating policies of the SERC and NERC and in accordance with the Operating Procedures to be developed by the Operating Committee. For the avoidance of doubt, the requirements of this Section 11.1.1 shall not be interpreted to limit Buyer's Scheduling rights as provided for elsewhere in this Agreement.

11.1.2 Seller and Buyer shall mutually develop and agree upon written Operating Procedures no later than one (1) Month prior to the Delivery Commencement Date. Topics covered shall include deliveries of energy during startup and testing of the Facility; the method of Day-to-day communications; daily capacity availability and energy reports; technical limits regarding Facility operation (including minimum run times, maximum ramp rates, minimum down times between starts, quick start capability and other limits specified in **Appendix C**); ramp rates for the delivery of power to the Transmission System; coordination of maintenance scheduling; designation of confidential information and such other matters as the Operating Representatives shall agree are appropriate. The Operating Representatives shall be responsible for modifying, from time to time, these Operating Procedures in writing to reflect agreed upon changes. In the event of inconsistency or conflict between the Operating Procedures and specific terms of this Agreement, the specific terms of this Agreement shall take precedence.

11.1.3 Seller shall employ at the Facility all safety devices and safety practices required by Prudent Industry Practices. Seller shall keep accurate records of any accident or other occurrence at the Site that results in injury to persons or damage to property. Seller shall provide to Buyer reasonable access to these records upon not less than seven (7) Days' notice during normal business hours, but shall not be required to provide access to employment records regarding Facility personnel.

11.1.4 During the Term, Seller shall employ or cause to be employed qualified and trained personnel for management, operation, and maintenance of the Facility.

11.2 Maintenance Scheduling.

11.2.1 Commencing in the year of the Delivery Commencement Date and by October 1 of each year thereafter, Seller shall submit to Buyer planned maintenance schedules, including the scope of the maintenance, and outage plans for the Facility that conform to Prudent Industry Practices for similar equipment, including in terms of frequency and duration ("Maintenance Schedules"), for the next four (4) Annual Periods or the number of such Annual Periods remaining in the Term, whichever is less. The first Maintenance Schedule shall be delivered on or before March 1, 2024. Seller shall not schedule any maintenance of the Facility during any of the Months of December, January or February or June, July, August, or September of any Annual Period that would decrease the capacity output of the Facility below the Designated Capacity without the prior written consent of Buyer. Buyer shall have thirty (30) Days to review the proposed Maintenance Schedules and may approve or reject the Maintenance Schedules in whole or in part. The Maintenance Schedules are subject to the approval of Buyer, which approval shall not be unreasonably withheld or delayed; provided, however, any determination by Buyer to disapprove a Hot Gas Path Inspection or Major Inspection commencing in May or November, or both, shall not be considered unreasonable. If any portion of the Maintenance Schedules is rejected by Buyer, Seller shall resubmit revised Maintenance Schedules to Buyer within thirty (30) Days of Buyer's rejection and Buyer and Seller agree to use best efforts to promptly develop Maintenance Schedules that are mutually acceptable to the Parties considering the burdens that Buyer's changes impose on Seller compared to the burdens avoided by Buyer as a result of such changes. Any dispute concerning this Section 11.2.1 shall be resolved in accordance with the provisions of Article 20 applicable to Maintenance Schedule disputes. The outages scheduled in the final, approved Maintenance Schedule shall be the "Scheduled Outages" for purposes of this Agreement.

11.2.2 In addition to Scheduled Outages, Seller may request an unlimited number of Maintenance Outages during any Annual Period. Seller shall request each Maintenance Outage no less than twenty-four (24) hours in advance and at least one (1) Business Day in advance. Such request shall identify the equipment and Designated Capacity that will not be available for Scheduling and the proposed start time and duration of the Maintenance Outage. Buyer shall respond to Seller's request as soon as reasonably practicable. Seller shall not take a Maintenance Outage without Buyer's prior written or

telephonic consent, and such consent shall not be unreasonably withheld, conditioned or delayed; provided, however, that the Parties acknowledge that it shall be reasonable for Buyer to deny any request for a Maintenance Outage if Buyer reasonably believes that it may Schedule the Facility to a level that would require the availability of the equipment that is proposed to be Unavailable during the Maintenance Outage. Buyer shall have the right to revoke its consent to a Maintenance Outage with at least twenty-four (24) hours' notice prior to the commencement of such Maintenance Outage if changed conditions require Scheduling of the Designated Capacity scheduled to be Unavailable during such Maintenance Outage. If Buyer reasonably requests Seller to return all or part of that portion of the Facility that is affected by the Maintenance Outage to full availability status, Seller shall comply as soon as reasonably practical.

11.2.3 If Seller has a Scheduled Outage, and such Scheduled Outage occurs or would occur coincident with a System Emergency, Buyer shall notify Seller of the System Emergency. Due to the System Emergency, Buyer may request Seller to reschedule the Scheduled Outage or, if the Scheduled Outage has begun, to expedite the completion thereof, and Seller shall comply with such request as soon as reasonably practical.

11.2.4 Buyer shall not submit Schedules for the delivery of energy under this Agreement to the extent that Facility is not capable of generating energy as a direct result of a Scheduled Outage or a Maintenance Outage approved by Buyer.

11.3 Permits. Seller shall maintain, for the period required by Legal Requirements during the Term, all Consents pertaining to air emissions necessary for the performance of Seller's obligations under this Agreement ("Air Permit"), including the operation of the Facility for up to eight thousand seven hundred sixty (8,760) hours per Annual Period throughout the Term; provided, however, the inability of Seller to cause compliance with such eight thousand seven hundred sixty (8,760) hours operating requirement shall not be deemed a Seller Event of Default so long as Seller completely covers for the remainder of the Term any such shortfall in the ability to meet Buyer's Schedules due to limitations in the Air Permit by electing to provide physical Alternate Delivery from an Alternate Resource in accordance with the provisions of Section 5.1.4.3. Seller shall provide a copy of the Air Permit to Buyer and shall promptly provide a copy of any renewal or amendment to the Air Permit to Buyer in accordance with the notice provisions of Section 21.4.

11.3.1 In the event of a Seller Event of Default resulting from the inability of Seller to cause compliance with the eight thousand seven hundred sixty (8,760) hours operating requirement in Section 11.3, the capacity and energy that would be considered available to Buyer under the Agreement in calculating the Termination Payment pursuant to the provisions of Section 17.3.3 shall be determined by utilizing the Facility's Air Permit limitations in effect on the Early Termination Date.

11.4 Access to the Site and the Facility. Seller grants to Buyer and its designated employees and agents the right to enter the Site with reasonable prior notice to Seller to: (i) inspect, maintain, and test meters and other Buyer equipment; (ii) monitor or measure energy generated by the Facility in accordance with the terms of this Agreement; (iii) monitor Performance Tests; (iv) inspect the Facility; and (v) inspect and test facilities related to the supply of Natural Gas. All activities of Buyer and its designated employees and agents at the Site shall be subject to the reasonable rules and procedures of Seller.

11.5 Availability of Records. Seller shall keep accurate records and all other data necessary for the purposes of proper administration of this Agreement in accordance with the following guidelines:

11.5.1 All records related to the Facility and Seller's performance under this Agreement shall be maintained for a minimum of five (5) years after the creation of such record or data and for any additional period of time required by Legal Requirements or a Governmental Authority; provided, however, that such records will be kept for as long as is necessary to complete any audit that began or was announced during such five-year period. Notwithstanding anything herein to the contrary, if Seller intends to dispose of or destroy any such records or data after such five-year period, Seller will provide Buyer with thirty (30) Days' prior written notice.

11.5.2 An accurate and up-to-date operating log shall be maintained at the Facility with records of: (i) real and reactive power production for each clock hour; (ii) changes in operating status and scheduled maintenance; (iii) Scheduled Outages, Maintenance Outages, Forced Outages and Force Majeure Events; (iv) any unusual conditions found during inspections; and (v) any significant events related to the operation of the Facility.

11.5.3 Upon reasonable advance notice and during normal business hours, Buyer shall have the right from time to time to examine the records and data relating to the Facility and this Agreement,

including historical test records relating to the Facility, at the Facility or at a location mutually agreed to by the Parties.

11.5.4 At the request of Buyer throughout the Term of the Agreement, Seller shall provide to Buyer public and non-public financial and business information reasonably necessary for Buyer to make accounting determinations. Without limiting the foregoing, upon reasonable notice to Seller, Buyer and Buyer's independent auditor will have the right to inspect, from time to time, such books and records of Seller as are reasonably necessary for Buyer to determine whether Seller constitutes a VIE and this Agreement represents a VI, or if this Agreement must be treated as a Finance Lease. To the extent such inspection requires access to confidential information of Seller, such information will constitute Confidential Information subject to the provisions of Section 21.13 of this Agreement.

11.6 Disclaimer. Seller understands and agrees that Buyer's receipt and/or review of any material related to any physical inspection of the Facility conducted by Buyer under any provision of this Agreement is solely for its own information. By conducting such reviews or inspections, Buyer makes no endorsement of the design or representation or warranty of the safety, durability or reliability of the Facility, all of which are the sole responsibility of Seller in accordance with the terms of this Agreement, and Buyer shall not be deemed to have accepted any condition of the Facility that is not in full compliance with the terms hereof. Seller shall in no way represent to any third party that, as a result of Buyer's receipt and review of any material or any inspections, Buyer is in any way responsible for the engineering or construction soundness of the Facility.

11.7 Operating Committee.

11.7.1 The Parties shall establish an Operating Committee comprised of two (2) Operating Representatives, one (1) appointed by each of Seller and Buyer. Seller and Buyer, as the case may be, shall provide written notice of such appointments to the other Party. Such appointments may be changed at any time by similar written notice. The Operating Representatives shall meet as necessary, but not less often than once each calendar year, at a mutually agreeable time and place upon prior written notice. The Operating Representatives shall represent the Parties in all matters arising hereunder that may be delegated to them by mutual agreement of the Parties, but shall not have any authority to modify or amend the terms of this Agreement.

11.7.2 Each Party shall cooperate in providing to the Operating Representatives all information required in the performance of their duties. If the Operating Representatives are unable to agree on any matter falling under their jurisdiction, such matter shall be submitted to senior officers of the Parties for discussion and resolution. All decisions and agreements made by the Operating Representatives or their principals shall be evidenced in writing.

ARTICLE 12

FUEL SUPPLY; ALLOWANCES

12.1 Overview.

12.1.1 Prior to the Delivery Commencement Date, Seller shall acquire and pay for any Natural Gas used at the Facility. At all times following the Delivery Commencement Date during the Term, the Facility shall be capable of utilizing Natural Gas as Scheduled by Buyer in order to produce the energy committed to Buyer under this Agreement. Buyer shall have the responsibility for developing a gas supply plan for procuring and making available at the Primary Gas Delivery Point the quantities of Natural Gas required by Seller, and at the rates of delivery and at an allowable pressure as specified in **Appendix C** to accommodate Buyer's Scheduling Instructions (the "Gas Supply Plan").

12.1.2 In accordance with **Appendix B**, Section E, Buyer shall receive or pay, as the case may be, a Monthly Fuel Adjustment based on the Guaranteed Heat Rate set forth in **Appendix J** for all Natural Gas used to generate energy that is delivered to Buyer pursuant to Buyer's Scheduling Instructions, including ramping (i) from synchronization to Minimum Capacity (Startup Energy); (ii) from Minimum Capacity to the maximum Energy output of the Facility; and (iii) down from such higher output levels to a lower output level or offline. Such ramping energy shall be multiplied by the appropriate Guaranteed Heat Rates pursuant to **Appendix J** to determine the Daily Guaranteed Fuel quantity during ramping. For greater certainty, Buyer shall be responsible for the cost of Natural Gas for start-up of the Facility prior to synchronization. The Parties shall be responsible in accordance with the provisions of **Appendix A**, Section A.2 for the cost of Natural Gas, including transportation charges, required for Performance Testing.

12.2 Natural Gas Transportation Capacity.

12.2.1 Except as otherwise provided in this Article 12, Buyer shall bear all of the costs incurred under the Gas Supply Plan. To the extent Buyer desires to have or use storage capacity in order to better manage the Natural Gas requirements of the Facility, Buyer shall be obligated to obtain such capacity at its expense.

12.2.2 **REDACTED REDACTED REDACTED

energy as committed to Buyer under this Agreement, including without limitation all costs associated with the operation of the gas pipeline lateral(s) necessary to connect the Facility to the gas pipeline(s) of the fuel supplier(s).

12.2.4 Seller agrees to accept and Buyer agrees to deliver at the Primary Gas Delivery Point any Natural Gas that (i) meets the gas quality standards for delivered Natural Gas under the applicable gas transportation provider's FERC gas tariff and the applicable transportation agreement(s), or (ii) does not meet the gas quality standards described in (i) so long as such Natural Gas would not, in Seller's reasonable discretion, have a material adverse effect on the Facility, or (iii) Seller allows to flow beyond the Primary Gas Delivery Point..

12.2.5 The Parties shall exercise commercially reasonable efforts to minimize any imbalances or other penalties or charges from transporters of Natural Gas delivered to the Facility ("Imbalance Charges"). Buyer shall be responsible for all Imbalance Charges relating to delivery of Natural Gas to the Facility to meet Buyer's Scheduling Instructions. If Buyer or Seller receives an invoice from a transporter for Imbalance Charges, the Parties shall determine the cause for such charges. To the extent that the Imbalance Charges were incurred as a result of Buyer's actions or inaction, then Buyer shall pay such Imbalance Charges. To the extent that the Imbalance Charges were incurred as a result of Seller's actions or inaction, or a Forced Derate associated with attempting to respond to Buyer's Schedule, then Seller shall pay such Imbalance Charges. Imbalance Charges that are not due to the action or inaction of Buyer or Seller or whose cause cannot be determined shall be shared equally by Buyer and Seller. Any disputes under this Section 12.2.5 shall be resolved in accordance with the provisions of Article 20 applicable to Imbalance Charges disputes.

12.2.6 All Natural Gas supplied by Buyer pursuant to this Agreement shall be measured at the Primary Gas Delivery Point. Buyer shall retain title to Natural Gas provided by Buyer to meet Buyer's Schedules. The title to all energy generated by the Facility as a result of the conversion of such Natural Gas to energy in the Facility shall vest in Buyer immediately upon generation thereof and pursuant to this tolling arrangement, Seller shall make the Facility available to Buyer to convert Buyer's Natural Gas to Buyer's energy. Notwithstanding the foregoing, risk of loss of Natural Gas supplied by Buyer pursuant to this Agreement shall transfer from Buyer to Seller at the Primary Gas Delivery Point and Seller shall bear

the risk of loss of energy generated at the Facility until it is transferred from Seller to Buyer at the Point of Interconnection.

12.3 Allowances.

12.3.1 All NOx Allowances and SO_2 Allowances that are allocated to or for the Facility, or that are otherwise granted to Seller for the Facility, by any Governmental Authority or pursuant to any Legal Requirement or Consent, including through any type of state or federal set-aside program, for the calendar years covered, in whole or in part, by the Annual Periods (such NOx Allowances, the "Facility NOx Allowances", and such SO_2 Allowances, the "Facility SO_2 Allowances") shall be reserved by Seller for the sole benefit of Buyer, and Seller shall use, at no cost to Buyer, all Facility NOx Allowances and Facility SO_2 Allowances for NOx Emissions and SO_2 Emissions, respectively, from the Facility resulting from energy generated to meet Buyer's Scheduling Instructions. If NOx Emissions or SO2 Emissions from the Facility resulting from energy generated to meet Buyer's Scheduling Instructions exceed the Facility NOx Allowances or Facility SO_2 Allowances, respectively, then Buyer shall be required to obtain and supply, at Buyer's expense, any additional NOx Allowances or SO_2 Allowances, as applicable, required for such NOx Emissions or SO2 Emissions in excess of the Facility NOx Allowances or Facility SO_2 Allowances; provided, however, that Buyer shall not be required to provide any NOx Allowances or SO_2 Allowances that are needed due to Seller exceeding the emission rates allowed by the Air Permit, any Consent, and any other applicable Legal Requirements. In no event shall Seller transfer any Facility NOx Allowances or Facility SO_2 Allowances to any other Person at any time or otherwise use Facility NOx Allowances or Facility SO_2 Allowances for any purpose other than the NOx Emissions and SO2 Emissions from the Facility resulting from energy generated to meet Buyer's Scheduling Instructions.

12.3.1.1 In the event that Seller is allocated, issued or has the right to obtain NOx Allowances or SO_2 Allowances for a portion of, or its entire fleet of, generating units, then a proportional amount of such NOx Allowances or SO_2 Allowances shall be reserved as Facility NOx Allowances or Facility SO_2 Allowances, as applicable, for Buyer's benefit in accordance with this Section 12.3; provided, however, that such reserved amount of Facility NOx Allowances or Facility SO_2 Allowances shall not exceed the amount required to meet the compliance obligations of the Facility under this Section 12.3 and Seller shall be entitled to receive the benefit of any excess Facility NOx Allowances or Facility

SO_2 Allowances. The proportional amount of NOx Allowances and SO_2 Allowances shall be calculated based on the method, formula or other similar calculation used by the Governmental Authority to determine the amount of such NOx Allowances and SO_2 Allowances attributable to each generating unit compared to the sum of all NOx Allowances and SO_2 Allowances for all generating units of Seller. For purposes of this Section 12.3.1.1, all references to "Seller" shall be deemed to include Seller's Affiliates or other entity to which NOx Allowances or SO_2 Allowances may be or have been allocated to or given rights to obtain for the Facility.

12.3.2 If for any period the Facility NOx Allowances or Facility SO_2 Allowances exceed the number of NOx Allowances or SO_2 Allowances, respectively, required for emissions from the Facility resulting from energy generated to meet Buyer's Scheduling Instructions for such period, then Seller shall carry forward such excess Facility NOx Allowances or Facility SO_2 Allowances, as the case may be, to use for the benefit of Buyer in accordance with Section 12.3.1 in future periods to the extent such Facility NOx Allowances and Facility SO_2 Allowances are allowed to be carried forward. At the end of the Term, Seller shall, to the extent permitted by Legal Requirements, transfer any and all such excess Facility NOx Allowances and Facility SO_2 Allowances to Buyer, and Buyer may utilize such Facility NOx Allowances and Facility SO_2 Allowances for any purpose in its sole and absolute discretion. Such excess Facility NOx Allowances and Facility SO2 Allowances shall be pro-rated, if necessary, so that Buyer receives only those Allowances that apply to the Term and not those that apply to the period before or after the Term.

12.3.3 Buyer shall not be required to provide any NOx Allowances and SO_2 Allowances that are required with respect to any Alternate Resource, and Seller shall be responsible, at Seller's expense, for obtaining all NOx Allowances and SO_2 Allowances required for any Alternate Resource.

12.3.4 Subject to Section 18.1 with respect to GHG Costs, Seller shall be solely responsible, at its sole cost and expense, for any and all other emission allowances other than NOx Allowances and SO_2 Allowances that are required in connection with the Facility, including for any emissions or energy produced therefrom.

ARTICLE 13

ENERGY SCHEDULING AND TRANSMISSION

13.1 Energy Scheduling. Buyer shall issue Scheduling Instructions for the electrical output committed under this Agreement. Buyer has the right to Schedule the Facility on AGC or non-AGC. As soon as practicable after the Execution Date, the Parties hereby agree to cooperate with the applicable Transmission Providers, Balancing Authorities (as defined by NERC) and Transmission Operators (as defined by NERC) to establish a Dynamic Schedule (as defined by NERC) for the purpose of transmitting Delivered Energy in real time from the Facility to the Buyer's load in the Southern Balancing Authority Area.

13.2 Coordination and Scheduling.

13.2.1 Notwithstanding any other provision of this Agreement, Buyer agrees to submit and Seller agrees to receive Schedules of the Facility in accordance with the procedures set forth in this Section 13.2 and **Appendix C**. Seller is not obligated to deliver energy in response to those portions of Scheduling Instructions that materially deviate from such procedures. Buyer is not entitled to Schedule energy, and Seller is not obligated to deliver such energy, to the extent that such energy cannot be delivered due to (a) Buyer's failure to deliver to the Facility a sufficient quantity of fuel to generate such energy at the Guaranteed Heat Rate, or (b) Buyer's inability to receive such energy at the Point of Interconnection.

13.2.2 The electrical output committed under this Agreement shall be subject to Scheduling Instructions issued by the Scheduling Center. Seller shall comply with such Scheduling Instructions at the time designated for compliance therewith, subject to the Technical Limits and the Scheduling procedures set forth in **Appendix C**.

13.2.3 Buyer and Seller shall maintain written (or electronically captured) records of the quantities of energy to be delivered each hour during the Term. Following the Delivery Commencement Date, Buyer may Schedule energy at any time during the Term and, subject to the terms of this Agreement, Seller shall cause the entire output capability of the Facility to be available to Buyer when Scheduled.

13.2.3.1 If Buyer elects to Schedule energy for delivery on the next Business Day, Buyer shall provide its Schedule for such delivery to Seller no later than 9:30 a.m. CPT on the Business Day prior to the Day of delivery for deliveries from the Facility, and no later than 9:00 a.m.

CPT on the Business Day prior to the Day of delivery for deliveries from an Alternate Resource. This Day-ahead Scheduling Instruction will also include any electric deliveries from midnight to midnight for any calendar Days that precede the next Business Day (*i.e.,* weekends and holidays). Buyer shall also provide a non-binding, good faith estimate of its Scheduling Instructions for the twenty-four (24) hour period following the next Business Day. Buyer will be required to accept and pay for energy during ramp up and ramp down periods at a price as described in **Appendix B**.

13.2.3.2 For Scheduling Instructions submitted after the Day-ahead deadline, Buyer must provide Seller with a proposed revised Schedule at least one (1) hour prior to the start-up or ramp up of energy delivery; provided, however, that Seller's obligation to comply with such Scheduling Instructions at the time designated for compliance therewith shall be subject to the Technical Limits. If energy is not already Scheduled, Buyer will be assessed one or more turbine start events, as applicable, in accordance with **Appendix B,** Section C. Buyer will be responsible for the actual costs (commensurate with the Guaranteed Heat Rate) of implementing the intra-Day Scheduling Instruction (including any associated imbalance penalties, if any, assessed by the Transmission Provider); provided, however, such costs shall not include any lost opportunity costs for power sales from the Facility.

13.2.3.3 Notwithstanding anything contained in Section 13.2.3.2 to the contrary, in the event Seller has provided notice that an Unavailability Event has occurred prior to Buyer giving intra-Day Scheduling Instructions, the most recent Schedule submitted by Buyer shall be deemed the Schedule for the balance of such Day in which the Seller has provided notice that the Unavailability Event has occurred. For each Day of the Unavailability Event until the return of the Facility to service, Buyer shall have the right to submit a Day-ahead Schedule and one (1) intra-Day Schedule for the balance of such Day and shall not change such Schedule for the balance of such Day. During an Unavailability Event, Seller shall inform Buyer regularly as to the projected schedule of the return to service of the Facility. If the Facility is able to return to service, Seller must notify Buyer by 3:00 p.m. CPT the previous Day to be able to deliver the entire Schedule requested by Buyer from the Facility. If the Facility is able to return to service intra-Day, Seller must give a three-hour notification of ability to operate. Buyer then has the right to submit a new Schedule for the balance of that Day. The previous Day's Schedule remains the obligation of Seller until the end of the three-hour notification. If Buyer chooses to Schedule zero (0) MWh for the

balance of the Day, there is no obligation for Seller for the remainder of that Day. If Buyer chooses to Schedule the Facility for greater than the Minimum Capacity, the new forward Schedule becomes Seller's delivery obligation for the remainder of that Day.

13.2.4 Seller may from time to time request that the Facility be allowed to deliver electric energy output to Buyer in order to test and/or evaluate Facility equipment ("Operator Requested Schedule"). Seller shall request such Operator Requested Schedule from Buyer at least one (1) Business Day in advance and Buyer shall have the right to approve such Operator Requested Schedule (such approval not to be unreasonably withheld, conditioned or delayed). If Buyer approves and subsequently determines that it is necessary to Schedule the Facility during an Operator Requested Schedule, then Buyer may cancel or interrupt, as the case may be, the Operator Requested Schedule and subsequently Schedule the Facility as it deems appropriate; provided, however, Buyer shall reimburse Seller for any reasonable, incremental expenses incurred by Seller due to Seller's reliance on Buyer's previous approval of the Operator Requested Schedule.

13.2.5 The Parties recognize that Buyer is a FERC jurisdictional entity subject to the reliability authority of NERC and that, to ensure continuous and reliable electric service, Buyer operates its system in accordance with the operating criteria and guidelines of NERC. If a System Emergency is declared and the Scheduling Center, at its sole discretion, identifies the need to modify the schedule or dispatch of the Facility, the Scheduling Center will notify Seller's personnel and, if requested, Seller's personnel shall immediately place the energy of the Facility within the exclusive control of the Scheduling Center for the duration of such System Emergency; provided, however, in such event, Buyer shall ensure that the Scheduling Center does not cause the Facility to be operated in a manner that exceeds the Technical Limits or any operations-related limits in the Air Permit without the prior written consent of Seller, and, notwithstanding Seller's consent, Buyer shall be responsible for all costs associated with operation of the Facility pursuant to such Scheduling Center control, including any penalties imposed on Seller by any Governmental Authority or costs incurred by Seller associated with additional maintenance or accelerated maintenance, in accordance with Prudent Industry Practices, due to such event. Without limiting the generality of the foregoing, the Scheduling Center may require Seller's personnel to raise or lower production of energy generated by the Facility, including potential start-up and/or shutdown situations, to

maintain safe and reliable load levels and voltages on the Transmission System. To the extent Seller is required, pursuant to this Section 13.2.5, to take any action, or the Scheduling Center takes any action, which will adversely affect Seller's ability to meet Buyer's Schedules, including those Schedules modified pursuant to Section 13.2.6, Seller shall be excused from meeting Buyer's Schedules and, for purposes of the Monthly Availability Percentage calculation, such hours (or equivalent hours) of Unavailability shall be subtracted from Unplanned Forced Outage Hours and Equivalent Unplanned (Forced) Derate Hours and such hours (or equivalent hours) of Unavailability shall be subtracted from Dispatch Hours, as shown in the MAP formulas in Section C-1 of **Appendix A.**

13.2.6 Seller shall cooperate with Buyer in establishing System Emergency plans, including (without limitation) recovery from a local or widespread electrical blackout, voltage reduction in order to effect load curtailment, and other such plans that may be necessary or appropriate under the circumstances.

13.3 AGC. Seller shall, at its sole cost and expense, install and test by the Delivery Commencement Date, all equipment and systems necessary in order to make the Facility capable of operating by AGC (as defined below). The AGC installation shall include all necessary connections to the equipment and systems of Buyer. Buyer shall cooperate reasonably with Seller in making such connections, which connections shall be to the reasonable satisfaction of Buyer. For the Term: (i) Seller shall at its sole cost and expense maintain and be responsible for the AGC equipment and systems installed and located up to Buyer's remote terminal unit; and (ii) Buyer shall at its sole cost and expense maintain and be responsible for its AGC-related equipment and systems located on its own side of Buyer's remote terminal unit. The Parties acknowledge and agree that the AGC equipment and systems will rely on a telecommunications company providing a communication link between Seller and Buyer. For purposes of this Agreement, "AGC" shall mean the automatic adjustment of the output of Facility generation to keep generation and load in balance in real time.

13.3.1 Seller shall enable Buyer to send an AGC signal to the Facility and to measure, record and control electric energy produced by the Facility at any instant in time. Seller shall be responsible for all costs and expenses associated with causing the Facility to respond to Buyer's AGC signals.

13.3.2 Buyer may elect, in its sole discretion, to Schedule the Facility utilizing AGC or by providing any other electronic or written instructions to Seller, provided that the Operating Committee shall agree upon the method(s) for communicating such instructions.

13.3.3 Buyer may Schedule the Facility utilizing AGC in automatic or manual control, subject to this Article 13 and **Appendix C.** If at any time the Facility is not capable of responding to AGC signals, Seller shall promptly re-establish AGC capability at its sole cost and expense.

13.4 Effect of Grid Emergencies. The Parties recognize that pursuant to the Interconnection Agreement, Seller may be required to reduce generation or take certain actions during a Grid Emergency and may be required to disconnect the Facility from the Transmission System to allow mitigation of system problems and repair or maintenance on the Interconnection Facilities or the Transmission System. To the extent that Seller is required pursuant to the Interconnection Agreement to take any action, other than instances where Seller's acts or omissions are the cause for the required actions, which will adversely affect its ability to meet Buyer's Schedules, Seller shall be excused from meeting Buyer's Schedules and, for purposes of the MAP calculation, such hours (or equivalent hours) of Unavailability shall be subtracted from Unplanned Forced Outage Hours and Equivalent Unplanned (Forced) Derated Hours and such hours (or equivalent hours) of Unavailability shall be subtracted from Dispatch Hours, as shown in the MAP formulas in Section C-1 of **Appendix A.**

13.5 Effect of Insufficient Capability in the Transmission System. In the event that the Transmission System is unable to receive the Scheduled energy from the Facility, Seller shall be excused from meeting Buyer's Schedules and, for purposes of the MAP calculation, such hours (or equivalent hours) of Unavailability shall be subtracted from Unplanned Forced Outage Hours and Equivalent Unplanned (Forced) Derate Hours and such hours (or equivalent hours) of Unavailability shall be subtracted from Dispatch Hours, as shown in the MAP formulas in Section C-1 of **Appendix A.**

ARTICLE 14

INSURANCE

14.1 Insurance Required of Seller. Throughout the Term, Seller must acquire and maintain, at its sole cost and expense, the types and amounts of insurance coverage as are consistent with Prudent

Industry Practices, but in no event less than the types and amounts described in this Article 14.

14.2 Proof of Insurance. Buyer, in its sole discretion, may require Seller to deliver to Buyer, at any time during the Term, but at least thirty (30) Days after the Effective Date and thereafter annually on the Delivery Commencement Date anniversary, a certificate of insurance certifying Seller's coverage under insurance policy(ies) issued by a reputable insurance company authorized to do business in the state where the Facility is located.

14.3 General Terms. The required insurance coverage must contain a broad form contractual endorsement specifically covering liabilities arising out of or caused by the operation of the Facility or by Seller's failure to maintain the Facility in satisfactory and safe operating condition. Seller's insurance must be primary for any activity arising out of this Agreement. Insurance or self-insurance maintained by Buyer or other additional insureds is in excess of Seller's insurance, contingent and non-contributory. To the extent allowed by applicable law, Buyer and its Representatives must be additional insureds under the commercial general liability policy, auto liability policy and, if applicable, excess/umbrella policy. To the extent allowed by applicable law, Seller waives, and must require its insurers to waive, a right of subrogation against Buyer and its Representatives for the commercial general liability policy, auto liability policy, umbrella policy, if applicable, and the workers' compensation policy.

14.4 General Liability Insurance. This insurance policy must provide the following coverage, which can be exceeded by Seller and may be met through any combination of primary insurance and following form excess or umbrella insurance, so long as the combined limits meet requirements of this Agreement:

14.4.1 Commercial general liability insurance in an "occurrence" form with bodily injury and property damage combined liability limits of not less than twenty million dollars ($20,000,000.00) per occurrence; provided, however: (i) Seller may use any combination of primary or excess policies to satisfy the overall limit requirements; and (ii) if Seller uses a "claims-made" policy, it must maintain continuous coverage in effect for at least five (5) years beyond termination of this Agreement, through continuous renewal of the original policy or by purchasing extended discovery period or retroactive insurance dated back to the Effective Date of this Agreement.

14.4.2 Specific coverage for broad form contractual liability and a separation of insureds

provision.

14.5 Additional Insurance. In addition to the requirements above, Seller must acquire and maintain throughout the Term, the following additional types of insurance:

14.5.1 Workers' Compensation. Workers' compensation insurance in accordance with statutory requirements, including employer's liability insurance, with limits not less than one million dollars ($1,000,000.00) per occurrence and endorsement providing insurance for obligations under the U.S. Longshoremen's and Harbor Worker's Compensation Act and the Jones Act, where applicable.

14.5.2 Auto Liability. Automobile liability insurance including owned, non-owned and hired automobiles with combined bodily injury and property damage limits of at least two million dollars ($2,000,000.00).

14.5.3 Pollution Liability. Coverage for bodily injury, property damage, including clean-up costs and defense costs resulting from sudden and accidental pollution conditions, including the discharge, dispersal, release or escape of smoke, vapors, soot, fumes, acids, alkalis, toxic chemicals, hydrocarbons, liquids or gases, waste materials or other irritants, contaminants or pollutants into or upon land, the atmosphere or any water course or body of water shall be maintained, with limits not less than one million dollars ($1,000,000.00) per occurrence or claim; provided, however, that, if Seller uses a "claims-made" policy, the policy must maintain continuous coverage in effect for at least five (5) years beyond termination of this Agreement through continuous renewal of the original policy or by purchasing extended discovery period retroactive insurance dated back to the Effective Date of this Agreement.

14.6 All Risk Property. Replacement cost of the Facility. A deductible may be carried, which will be the absolute responsibility of Seller.

14.7 Notice of Change or Cancellation. The required insurance policies will be endorsed with a provision requiring the insurance company to notify Buyer at least thirty (30) Days prior to the effective date of any cancellation, with the exception of a ten (10) Days' notice for nonpayment of premium. If notice of cancellation is only commercially available to Seller's attention, then Seller will forward such thirty (30) Day (or, for non-payment of premium, ten (10) Day) advance notice to Buyer immediately upon receipt. Furthermore, Seller agrees to notify Buyer at least thirty (30) Days prior to the effective date of any known material change in a required policy.

14.8 Payment of Premiums. Seller will pay all premiums and other charges due on each insurance policy and will keep all coverage in force throughout the Term of this Agreement.

14.9 No Waiver of Liability. The provisions requiring Seller to acquire and maintain insurance under this Agreement will not be construed as a waiver, restriction or limitation of any liability imposed on Seller under this Agreement, whether or not the same is covered by insurance. It is the intent of the Parties, however, that to the extent there is insurance coverage available to cover the legal or contractually assumed liability of Seller, any payments due as a result of such liability will be made first from the proceeds of such policies.

ARTICLE 15

INDEMNIFICATION

15.1 Seller Indemnity.

15.1.1 Seller shall release, defend, indemnify and hold harmless Buyer and its Affiliates and the directors, officers, representatives, agents, and employees of each of them ("Buyer Indemnitees"), from and against any and all loss, damages and claims of third Persons, and all liabilities to third Persons (including claims and actions of such third Persons involving injury to or death of any person or damage to property, damages, penalties, demands, fines, forfeitures, suits, actions and causes of action and all costs and expenses incident thereto), including court costs, costs of defense, costs of investigation, settlements, judgments, and attorneys' fees, in each case arising or resulting from the use and operation of the Facility and all activities occurring on Seller's side of the Point of Interconnection or Seller's side of the Primary Gas Delivery Point, including those which are alleged to arise or result from: (i) environmental permitting; (ii) failure by Seller to comply with any Consent or Legal Requirement; (iii) Seller's failure to perform its obligations under this Agreement; and (iv) any negligent, wanton, or intentional wrongful act or omission of Seller or anyone employed by Seller.

15.1.2 If Buyer or any Buyer Indemnitees become entitled to indemnification under Section 15.1.1, Buyer shall promptly notify Seller of any claim or proceeding in respect of which it is to be indemnified. Such notice shall be given as soon as reasonably practicable after the Buyer becomes aware of such claim or proceeding. Failure to give such notice shall not excuse an indemnification obligation.

Seller shall assume the defense thereof with counsel designated by Buyer; provided, however, that if the defendants in any such action include both Seller and Buyer, and if Buyer reasonably concludes that there may be legal defenses available to it that are different from or additional to, or inconsistent with, those available to the Seller, Buyer shall have the right to select and be represented by separate counsel, at the expense of Seller. If Seller fails to assume the defense of a claim, the indemnification of which is required under this Agreement, Buyer may, at the expense of Seller, contest, settle, or pay such claim.

15.2 Buyer Indemnity

15.2.1 Buyer shall release, defend, indemnify and hold harmless Seller and its Affiliates and the directors, officers, representatives, agents, and employees of each of them ("Seller Indemnitees"), from and against any and all loss, damages and clams of third Persons, and all liabilities to third Persons (including claims and actions of such third Persons involving injury to or death of any person or damage to property, damages, penalties, demands, fines, forfeitures, suits, actions and causes of action and all costs and expenses incident thereto), including court costs, costs of defense, costs of investigation, settlements, judgments, and attorneys' fees, in each case arising or resulting from Buyer's activities in performing its obligations under this Agreement that occur on Buyer's side of the Point of Interconnection or Buyer's side of the Primary Gas Delivery Point, including those which are alleged to arise or result from: (i) failure by Buyer to comply with any Consent or Legal Requirement; (ii) Buyer's failure to perform its obligations under this Agreement; (iii) any negligent, wanton, or intentional wrongful act or omission of Buyer or anyone employed by Buyer; or (iv) acts or omission of Buyer's employees or agents on the Site.

15.2.2 If Seller or any Seller Indemnitees become entitled to indemnification under Section 15.2.1, Seller shall promptly notify Buyer of any claim or proceeding in respect of which it is to be indemnified. Such notice shall be given as soon as reasonably practicable after the Seller becomes aware of such claim or proceeding. Failure to give such notice shall not excuse an indemnification obligation. Buyer shall assume the defense thereof with counsel designated by Seller; provided, however, that if the defendants in any such action include both Seller and Buyer, and if Seller reasonably concludes that there may be legal defenses available to it that are different from or additional to, or inconsistent with, those available to the Buyer, Seller shall have the right to select and be represented by separate counsel, at the expense of Buyer. If Buyer fails to assume the defense of a claim, the indemnification of which is required

under this Agreement, Seller may, at the expense of Buyer, contest, settle, or pay such claim.

ARTICLE 16

FORCE MAJEURE

16.1 Definition of Force Majeure Event. For the purposes of this Agreement, a "Force Majeure Event" as to a Party means any occurrence, nonoccurrence or set of circumstances that prevents a Party, in whole or in part, from performing any of its obligations or satisfying any conditions under this Agreement and that is beyond the reasonable control of such Party (including such Party's contractors) and is not caused by such Party's (or such Party's contractors') negligence, lack of due diligence or failure to follow Prudent Industry Practices, or by such Party's breach of this Agreement. The term Force Majeure Event shall not include: (i) the inability to meet a Legal Requirement or the change in a Legal Requirement; (ii) a site-specific strike, walkout, lockout or other labor dispute at the Facility; (iii) equipment failure or equipment damage, unless, in the case of the Facility only, such equipment failure or equipment damage results directly from an event that would otherwise constitute a Force Majeure Event hereunder; (iv) changes in market conditions that affect the cost or availability of equipment, materials, supplies or services, including the Facility's fuel supply or the cost of power from resources other than the Facility; (v) any (a) inability by Buyer to obtain Natural Gas supply, (b) or failure by a Natural Gas transporter to deliver sufficient quantities of Natural Gas for Buyer to perform its obligations under this Agreement, or (c) inability by Buyer to receive energy at the Point of Interconnection, provided such inability is not caused by Seller's actions or inactions; (vi) failures of a Party's contractors, suppliers or vendors, unless such failure is caused by an event which would otherwise constitute a Force Majeure Event hereunder if directly experienced by the Party; (vii) ambient temperature and humidity at the Site being different than Referenced Conditions; and (viii) any event, including a change in any Legal Requirement or accounting standard, that requires Buyer to consolidate Seller or any of its Affiliates or permitted assigns as a VIE in Buyer's financial statements.

16.2 No Breach or Liability; Suspension of Performance. If a Force Majeure Event occurs, subject to compliance with Section 16.4 and Section 16.5, the affected Party will be excused from performance of its obligations hereunder, other than payment obligations that accrued prior to the declaration of the Force Majeure Event, and will not be construed to be in default in respect of such

obligations to the extent that, and for so long as, failure to perform is due to a Force Majeure Event. However, the suspension of performance due to a Force Majeure Event shall be of no greater scope and of no longer duration than is required by such Force Majeure Event. Notwithstanding anything herein to the contrary, no Force Majeure Event shall extend this Agreement beyond its stated Term.

16.3 Monthly Capacity Payments. In the case of an Unavailability Event caused by a Force Majeure Event declared by Seller pursuant to Article 16, if there are any Days of such Unavailability Event that are not covered by a Seller election of Alternate Delivery in accordance with Section 5.1.4.3, Buyer's obligation to make a Monthly Capacity Payment for any Month including such Days shall be excused pro rata, based on the number of such Days in the Month and to the extent that Seller is prevented on such Days from satisfying Scheduling Instructions from Buyer by the Force Majeure Event.

16.4 Notice of Force Majeure Event. Following the occurrence of a Force Majeure Event, and as a condition to relief under Section 16.2, the affected Party shall give the other Party notice thereof, followed by written notice if the first notice is not written, as promptly as possible after such Party becomes aware of such Force Majeure Event, describing the particulars of such Force Majeure Event, including an estimate of the anticipated duration and effect of the Force Majeure Event (if reasonably estimable) upon the performance of its obligations or satisfaction of any conditions under this Agreement (including, if Seller is the affected Party, Seller shall provide Buyer with information reasonably required to determine the amount of the reduction of the generating capability of the Facility), and discussing any actions being taken to avoid or minimize the effect of the Force Majeure Event. The affected Party shall have a continuing obligation to deliver to the other Party regular updated reports and any additional documentation and analysis supporting its claim regarding a Force Majeure Event. The burden of proof as to whether a Force Majeure Event has occurred and as to the impact of a Force Majeure Event shall be upon the affected Party.

16.5 Mitigation. The affected Party shall comply with the following requirements as a condition to the affected Party's right to relief under Section 16.2 due to a Force Majeure Event: (i) the affected Party shall continue to perform its obligations hereunder to the extent not affected by such Force Majeure Event; (ii) the affected Party shall remedy its inability to perform as soon as reasonably practicable; provided, however, that this Section 16.5 shall not require the settlement of any non-site specific strike, walkout,

lockout or other general labor dispute on terms which, in the sole judgment of the affected Party, are contrary to its interest; (iii) when the affected Party is able to resume performance of its obligations under this Agreement, the affected Party shall promptly provide written notice to the other Party, promptly resume such performance, and provide the other Party with a written certification from an independent, registered engineer reasonably acceptable to such other Party that the Force Majeure Event has been cured.

16.6 Extended Force Majeure Events.

16.6.1 If the affected Party has reason to believe that a suspension of performance due to a Force Majeure Event will continue for a period of six (6) Months or longer following the initial suspension of performance resulting from the Force Majeure Event (an "Extended Force Majeure Event"), the affected Party shall notify the other Party promptly and shall submit a "Force Majeure Remedy Plan" to the other Party within thirty (30) Days thereafter. In addition, if the other Party has reason to believe that a Force Majeure Event will be an Extended Force Majeure Event, the other Party may request that the affected Party submit a "Force Majeure Remedy Plan," which the affected Party shall submit to the requesting Party within thirty (30) Days of the request. A Force Majeure Remedy Plan shall set forth a plan and schedule for remedial measures (including necessary repairs, improvements, and changes to operations, as applicable) to cure the effects of the Force Majeure Event so as to enable the affected Party to resume full performance of the suspended obligations under this Agreement as soon as reasonably practicable.

16.6.2 While a Force Majeure Remedy Plan is in effect, the affected Party shall provide Monthly status reports to the other Party regarding the implementation of the Force Majeure Remedy Plan, any other measures to remedy the Force Majeure Event, any changes to the Force Majeure Remedy Plan, and the expected remaining duration of the suspended performance and shall provide any additional relevant information as may be reasonably requested by the other Party. The affected Party shall modify the Force Majeure Remedy Plan if and as needed to achieve the objective of resuming full performance of the suspended obligations under this Agreement as soon as reasonably practicable.

16.6.3 The Party not prevented from performing its obligations due to the Force Majeure Event may at any time terminate this Agreement effective upon ten (10) Days prior written notice to the affected Party if: (i) the affected Party fails to provide a Force Majeure Remedy Plan as required by this Section 16.6; or (ii) the affected Party fails to carry out the Force Majeure Remedy Plan in a method

reasonably designed to achieve the objective of resuming full performance of the suspended obligations under this Agreement as soon as reasonably practicable; or (iii) the affected Party remains unable to perform the suspended obligations under this Agreement twelve (12) Months following the initial suspension of performance resulting from the Force Majeure Event. For the purposes of subsection (iii) of this Section 16.6.3, the twelve (12) Month period need not be continuous if each period of suspension of performance comprising the twelve (12) Month period is the result of a common cause such that, if the cause had been cured following the first suspension of performance, the additional suspensions of performance would not have occurred.

16.6.4 Upon any termination of this Agreement as provided in Section 16.6.3, the Parties shall have no further liability or obligation to each other except for any obligation arising prior to the date of such termination.

ARTICLE 17

DEFAULT AND REMEDIES

17.1 Default by Seller. The occurrence of any of the following events shall constitute an Event of Default by Seller:

17.1.1 Any representation or warranty made by Seller herein or in any certificate or other document delivered to Buyer pursuant hereto shall prove to be incorrect in any material respect when made, unless Seller shall promptly commence and diligently pursue action to cause such representation or warranty to become true in all material respects and does so within thirty (30) Days after notice thereof has been given to Seller by Buyer (unless such cure is not capable of being effected within such thirty (30) Day period in which case Seller shall have an additional thirty (30) Day period in which to perform such cure) and such cure removes any material adverse effect on Buyer of such representation or warranty having been incorrect.

17.1.2 A court having jurisdiction shall enter: (i) a decree or order for relief in respect of Seller in an involuntary case or proceeding under any applicable Federal or state bankruptcy, insolvency, reorganization or other similar law; or (ii) a decree or order, the entry of which was sought by an entity other than Seller, adjudicating Seller bankrupt or insolvent, or approving as properly filed a petition seeking

reorganization, arrangement, adjustment or composition of or in respect of Seller under any applicable Federal or state law, or appointing a custodian, receiver, liquidator, assignee, trustee, sequestrator or other similar official of Seller or of any substantial part of its affairs.

17.1.3 Seller shall: (i) commence a voluntary case or proceeding under any applicable Federal or state bankruptcy, insolvency, reorganization or other similar law or any other case or proceeding to be adjudicated a bankrupt or insolvent; (ii) consent to the entry of a decree or order for relief in respect of Seller in any involuntary case or proceeding under any applicable Federal or state bankruptcy, insolvency, reorganization or other similar law or to the commencement of any bankruptcy or insolvency case or proceeding against it; (iii) file any petition, answer or consent seeking reorganization or similar relief under any applicable Federal or state law, which, if granted would have the effect of relieving Seller of any of its obligations; (iv) consent to the filing of any petition or to the appointment of or taking possession by a custodian, receiver, liquidator, assignee, trustee, sequestrator or similar official of Seller or of any substantial part of its property; (v) make an assignment for the benefit of creditors; (vi) admit in writing its inability to generally pay its debts as they become due; or (vii) take any action in furtherance of any of the foregoing.

17.1.4 Seller fails to comply or cause compliance with the Seller Performance Security requirements of Section 7.1, or Seller Guarantor breaches any of its obligations under the Seller Guaranty or if any representation or warranty made by Seller Guarantor in the Seller Guaranty shall prove to be incorrect in any material respect when made, unless any of the foregoing is cured by the end of the second Business Day following receipt of a written notice from Buyer of a failure under this Section 17.1.4.

17.1.5 Seller fails to perform or observe any material obligation of Seller under this Agreement, other than those obligations specifically addressed in Section 17.1, which failure continues for a period of thirty (30) Days after written notice thereof from Buyer unless such cure is not capable of being effected within such thirty (30) Day period, in which case Seller shall have an additional thirty (30) Day period in which to perform such cure.

17.1.6 Seller violates the requirements of Article 19 through an assignment or transfer of this Agreement or an ownership interest by Seller in the Facility or through a Change of Control, in each case, not otherwise permitted by the provisions of Article 19.

17.1.7 Seller fails to pay Buyer any undisputed amount payable by Seller to Buyer pursuant to this Agreement for fifteen (15) Days after the same shall have become due and payable and Seller fails to cure such failure to pay within fifteen (15) Days after receipt of written demand therefor from Buyer.

17.1.8 The Availability Percentage is below forty percent (40%) for any (i) one (1) Summer Season, or (ii) one (1) Winter Season during which five hundred (500) or more hours are Scheduled for each Month, or (iii) six (6) consecutive Months during which five hundred (500) or more hours are Scheduled for each Month; provided, however, that Seller may, within fifteen (15) Days after the end of such Season or six (6) Month period, as applicable, submit a cure plan that is reasonably acceptable to Buyer and expected to resolve the cause of the unsatisfactory Availability Percentage as soon as practicable, but in no event later than one hundred eighty (180) Days from the end of such Season or six (6) Month period, as applicable, unless such repairs cannot reasonably be completed within such period in which case, the repair period shall be extended to three hundred sixty-five (365) Days. If Seller fails to submit such a cure plan in a timely manner or fails to diligently pursue implementation of the cure plan, or if the unsatisfactory Availability Percentage is not, in fact, cured by the end of the one hundred eighty (180) Day period, then Buyer shall have the right to declare an Event of Default. The cause of the unsatisfactory Availability Percentage shall be cured only if (i) Seller is able to resume performance of its obligations under this Agreement and provides Buyer with a written certification reasonably acceptable to Buyer that the cause of the unsatisfactory Monthly Availability Percentage has been cured, and (ii) the Availability Percentage determined for the first full Month following Buyer's receipt of such certification of successful completion of the cure plan is at least sixty percent (60%). For the purposes of this Section 17.1.8, the "Availability Percentage" shall mean the percentage calculated for the relevant period using the MAP formulas shown in Section C-1 of **Appendix A**, with the calculation applied to the total relevant period and with ARDH equal to zero.

17.1.9 Notwithstanding any other provision of this Agreement, if the Tested Reliable Capacity of the Facility, determined pursuant to a Performance Test, at any time after the Delivery Commencement Date, is below seventy percent (70%) of the Designated Capacity for the applicable Season, and Seller fails to (i) submit to Buyer a cure plan reasonably acceptable to Buyer for such

inadequate Tested Reliable Capacity within ten (10) Days after determination by the Performance Test of such inadequate Tested Reliable Capacity, and (ii) cure such inadequate Tested Reliable Capacity within a reasonable period of time, not to exceed one hundred twenty (120) Days from the completion of the Performance Test ("Cure Period"); provided, however, that the Cure Period may be extended in accordance with Section 17.1.9.1 if Seller elects for the period of such extended Cure Period to cover (to the extent of the degraded capacity) Buyer's Schedules through an Alternate Resource in accordance with Section 5.1.4.3. Buyer shall have the right to declare an Event of Default if Seller fails to (i) establish the cure plan within the required ten (10) Day period or, if applicable, establish the revised cure plan within the required fifteen (15) Day period under Section 17.1.9.1, or (ii) diligently implement such cure plan (including implementation of such actions as Buyer may reasonably request), or (iii) cure the inadequate Tested Reliable Capacity within the Cure Period (as the Cure Period may be extended under Section 17.1.9.1) as set forth in Section 17.1.9.2.

17.1.9.1 In the event Seller establishes a cure plan in accordance with Section 17.1.9 but requires a Cure Period of more than one hundred twenty (120) Days to cure the inadequate Tested Reliable Capacity, then the Cure Period will be extended for a reasonable additional period of time, which extension will not in any case exceed four hundred twenty (420) Days, provided that Seller satisfies all of the following conditions to any such extension: no later than fifteen (15) Days prior to the expiration of the one hundred twenty (120) Days Cure Period, Seller shall provide to Buyer (i) a revised cure plan setting forth a reasonable extension of the Cure Period, not to exceed four hundred and twenty (420) Days, which revised cure plan and extension shall be reasonably acceptable to Buyer, and (ii) a written certification reasonably acceptable to Buyer confirming that in order for Seller to cure the inadequate Tested Reliable Capacity Seller must be afforded such reasonable additional period of time; and (iii) Seller's election for the period of such extended Cure Period to cover (to the extent of the degraded capacity) Buyer's Schedules through an Alternate Resource in accordance with Section 5.1.4.3. For the avoidance of doubt, the total duration of the Cure Period, as extended, shall not exceed five hundred and forty (540) Days.

17.1.10 The cause of the inadequate Tested Reliable Capacity shall be cured under Sections 17.1.9 only if (i) Seller provides Buyer with a written certification reasonably acceptable to Buyer

confirming that the inadequate Tested Reliable Capacity has been cured, and (ii) the inadequate Tested Reliable Capacity is increased to a value equal to or greater than seventy percent (70%) of the Designated Capacity for the applicable Season as demonstrated by the most recent Performance Test conducted during such Season. Throughout the duration of any Cure Period, the Designated Capacity will be deemed to be the Tested Reliable Capacity determined pursuant to the most recent Performance Test. Notwithstanding the foregoing provisions of Sections 17.1.9 and 17.1.9.1, whenever the Tested Reliable Capacity of the Facility determined pursuant to a Performance Test at any time after the Delivery Commencement Date is below seventy percent (70%) of the Nominal Capability, Buyer shall have the unilateral right to elect the remedy specified in **Appendix A**, Section A.4, in which case, such remedy shall be available for inadequate Tested Reliable Capacity above, at and below seventy percent (70%) of Nominal Capability. In order to elect such remedy Buyer must notify Seller in writing of this election and must waive its right in such notice to declare a Seller Event of Default under Sections 17.1.9 and 17.1.9.1 with respect to such specific event (but not any other additional events) of inadequate Tested Reliable Capacity

17.1.11 Seller breaches its obligation to deliver energy pursuant to Buyer's Schedule(s) to the extent that the Facility or a designated Alternate Resource, if applicable, is Available, and such breach continues for more than two (2) hours after Buyer provides Seller with written notice of such breach.

17.1.12 Seller, or any of its Affiliates, or any of their employees, contractors, subcontractors, agents or representatives willfully adjusts the Metering System or the Interconnection Facilities without Buyer's written consent and which adjustment has the effect of falsely increasing the amounts owed by Buyer under this Agreement.

17.1.13 Any failure of any covenant made by Seller in Section 3.3 herein (other than Section 3.3.3), unless Seller shall promptly commence and diligently pursue action to cure such failure within thirty (30) Days after notice thereof has been given to Seller by Buyer, (unless such cure is not capable of being effected within such thirty (30) Day period in which case Seller must submit a cure plan prior to the end of such thirty (30) Day period outlining steps to assure Buyer that the failure will be cured, which cure plan shall be subject to Buyer's approval, such approval not to be unreasonably withheld by

Buyer, but in no event shall the total cure period exceed one hundred and eighty (180) Days) and such cure removes any adverse effect on Buyer of such failure of such covenant.

17.1.14 Seller violates any Legal Requirement and such violation would have a material adverse effect on Seller's ability to perform under this Agreement and such violation is not cured within thirty (30) days after written notice from Buyer unless such cure is not capable of being effected within such thirty (30) Day period, in which case Seller shall have an additional thirty (30) Day period in which to commence such cure and thereafter diligently pursues such cure and completes such cure within sixty (60) Days and such cure removes any material adverse effect on Seller's ability to perform under this Agreement; provided, however, Seller shall be deemed not to have committed an Event of Default hereunder if Seller has validly contested the alleged violation, such matter remains pending before the applicable Governmental Authorities, and any cease and desist order or other enforcement action due to an alleged violation of the Legal Requirements has been stayed.

17.2 Default by Buyer. The occurrence of any of the following events shall constitute an Event of Default by Buyer:

17.2.1 Buyer fails to pay any undisputed amount payable by Buyer to Seller pursuant to this Agreement for fifteen (15) Days after the same shall have become due and payable and Buyer fails to cure such failure to pay within fifteen (15) Days after receipt of written demand therefor from Seller.

17.2.2 Buyer fails to perform or observe any material obligation of Buyer under this Agreement, other than those obligations included in this Section 17.2, which failure materially and adversely affects the ability of Seller or Buyer to perform their respective obligations under this Agreement and continues for a period of thirty (30) Days after written notice thereof from Seller (unless such cure is not capable of being effected within such thirty (30) Day period, in which case Buyer shall have an additional thirty (30) Day period in which to perform such cure.)

17.2.3 Any representation or warranty made by Buyer herein or in any certificate or other document delivered to Seller pursuant hereto shall prove to be incorrect in any material respect when made, unless Buyer shall promptly commence and diligently pursue action to cause such representation or warranty to become true in all material respects and does so within thirty (30) Days after notice thereof has been given to Buyer by Seller (unless such cure is not capable of being effected within such thirty (30) Day

period in which case Buyer shall have an additional thirty (30) Day period in which to perform such cure) and such cure removes any material adverse effect on Seller of such representation or warranty having been incorrect.

17.2.4 A court having jurisdiction shall enter: (i) a decree or order for relief in respect of Buyer in an involuntary case or proceeding under any applicable Federal or state bankruptcy, insolvency, reorganization or other similar law; or (ii) a decree or order adjudicating Buyer bankrupt or insolvent, or approving as properly filed a petition seeking reorganization, arrangement, adjustment or composition of or in respect of Buyer under any applicable Federal or state law, or appointing a custodian, receiver, liquidator, assignee, trustee, sequestrator or other similar official of Buyer or of any substantial part of its affairs.

17.2.5 Buyer shall: (i) commence a voluntary case or proceeding under any applicable Federal or state bankruptcy, insolvency, reorganization or other similar law or any other case or proceeding to be adjudicated a bankrupt or insolvent; (ii) consent to the entry of a decree or order for relief in respect of Buyer in any involuntary case or proceeding under any applicable Federal or state bankruptcy, insolvency, reorganization or other similar law or to the commencement of any bankruptcy or insolvency case or proceeding against it; (iii) file any petition, answer or consent seeking reorganization or similar relief under any applicable Federal or state law, which, if granted would have the effect of relieving Buyer of any of its obligations; (iv) consent to the filing of any petition or to the appointment of or taking possession by a custodian, receiver, liquidator, assignee, trustee, sequestrator or similar official of Buyer or of any substantial part of its property; (v) make an assignment for the benefit of creditors; (vi) admit in writing its inability to generally pay its debts as they become due; or (vii) take any action in furtherance of any of the foregoing.

17.2.6 Buyer violates the requirements of Article 19 through an assignment or transfer of this Agreement.

17.2.7 Buyer violates any Legal Requirement and such violation would have a material adverse effect on Buyer's ability to perform under this Agreement and such violation is not cured within thirty (30) days after written notice from Seller unless such cure is not capable of being effected within such thirty (30) Day period, in which case Buyer shall have an additional thirty (30) Day period in which to commence such cure and thereafter diligently pursues such cure and completes such cure within sixty (60)

Days and such cure removes any material adverse effect on Buyer's ability to perform under this Agreement. Provided, however, Buyer shall be deemed not to have committed an Event of Default hereunder if Buyer has validly contested the alleged violation, such matter remains pending before the applicable Governmental Authorities, and any cease and desist order or other enforcement action due to an alleged violation of the Legal Requirement has been stayed.

17.2.8 Any failure of any covenant made by Buyer in Section 3.4 herein, unless Buyer shall promptly commence and diligently pursue action to cure such failure within thirty (30) Days after notice thereof has been given to Buyer by Seller, (unless such cure is not capable of being effected within such thirty (30) Day period in which case Buyer must submit a cure plan prior to the end of such thirty (30) Day period outlining steps to assure Seller that the failure will be cured, which cure plan shall be subject to Seller's approval, such approval not to be unreasonably withheld by Seller, but in no event shall the total cure period exceed one hundred and eighty (180) Days) and such cure removes any adverse effect on Seller of such failure of such covenant.

17.3 Remedies.

17.3.1 If an Event of Default occurs at any time during the Term, the non-defaulting Party (the "Non-Defaulting Party") may, for so long as the Event of Default is continuing, subject to the provisions of Article 20, take one or more of the following actions: (i) establish a date (which date shall be no more than ten (10) Business Days after the Non-Defaulting Party delivers written notice of such date to the defaulting Party (the "Defaulting Party")) on which this Agreement shall terminate (the "Early Termination Date"), (ii) proceed by appropriate proceedings in accordance with this Agreement at law, in equity or otherwise, to protect and enforce its right to damages (actual or liquidated) or, where the Event of Default is one other than the failure to pay money, equitable relief, including specific performance, and (iii) immediately cease performance or withhold any payments, or both, due in respect of this Agreement.

17.3.2 If an Early Termination Date has been established, and the Non-Defaulting Party has not successfully pursued an action for specific performance, the Non-Defaulting Party shall in good faith calculate its Gains, Losses and Costs resulting from the termination of this Agreement, aggregate such Gains, Losses and Costs into a single net amount, and then notify the Defaulting Party. If the Non-Defaulting Party's aggregate Losses and Costs exceed its aggregate Gains, the Defaulting Party shall, unless it

disagrees with such calculation, within fifteen (15) Business Days of receipt of such notice, pay the net amount (the "Termination Payment") to the Non-Defaulting Party, which amount shall bear interest at the Interest Rate from the Early Termination Date until paid. If the Non-Defaulting Party's aggregate Gains exceed its aggregate Losses and Costs, if any, resulting from the termination of this Agreement, the Non-Defaulting Party may retain such Gains. If the Defaulting Party disagrees with the calculation of the Termination Payment, the issue shall be resolved pursuant to the provisions of Article 20 applicable to Termination Payment disputes, and the resulting Termination Payment shall be due and payable within three (3) Business Days after the award.

17.3.3 Subject to the provisions of Section 11.3.1, the Gains, Losses and Costs shall be determined by comparing the cost under this Agreement of the capacity and energy that would be available under this Agreement for the remainder of the Term had this Agreement not been terminated to the market price of capacity and energy of equivalent reliability and Scheduling flexibility for the remaining Term (had this Agreement not been terminated). For the avoidance of doubt, nothing in Article 7 is intended to limit liability under this Section 17.3. To ascertain such market price, the Non-Defaulting Party may consider, among other evidence, the settlement prices of NYMEX energy futures contracts, quotations from leading dealers in energy and gas swap contracts, offers for replacement capacity and energy or bids to purchase the remaining capacity and energy that was to be sold pursuant to this Agreement, in either case made by bona fide third-parties (including offers received by the Non-Defaulting Party in response to any request for proposals for capacity and energy contracts), all adjusted for the length of the remaining Term (had this Agreement not been terminated) and differences in locational basis (including without limitation costs of transmission investments and transmission service), reliability, Scheduling flexibility and any other considerations affecting value. Neither Party shall be required to enter into replacement transactions in order to determine the Termination Payment. As used in this Section 17.3.3: (i) "Costs" shall mean, brokerage fees, commissions and other similar transaction costs and expenses reasonably incurred by such Party either in terminating any agreement which it has entered into to fulfill its obligations hereunder or entering into new agreements which replace this Agreement, and attorneys' fees, if any, incurred in connection with enforcing its rights under this Agreement; (ii) "Gains" shall mean, an amount equal to the economic benefit determined on a mark to market basis (exclusive of Costs), if any, to the Non-Defaulting

Party resulting from the termination of this Agreement; and (iii) "Losses" shall mean an amount equal to the economic loss determined on a mark to market basis (exclusive of Costs), if any, to the Non-Defaulting Party resulting from the termination of this Agreement.

17.4 Rights of Specific Performance. In the case of an Event of Default, the Parties recognize that any remedy at law may be inadequate because this Agreement is unique and/or because the actual damages of the Non-Defaulting Party may exceed the amount of any guaranty or other collateral available to the Non-Defaulting Party. The Parties agree that in such an event, the Non-Defaulting Party shall be entitled to pursue an action for specific performance and the Defaulting Party waives all of its rights to assert as a defense to such action that the Non-Defaulting Party's remedy at law is adequate. For the avoidance of doubt, the Non-Defaulting Party shall not be entitled to receive both specific performance and a Termination Payment from the Defaulting Party.

17.5 Limitation of Remedies, Liability and Damages. **THE PARTIES CONFIRM THAT THE EXPRESS REMEDIES AND MEASURES OF DAMAGES PROVIDED IN THIS AGREEMENT SATISFY THE ESSENTIAL PURPOSES HEREOF FOR BREACH OF ANY PROVISION FOR WHICH AN EXPRESS REMEDY OR MEASURE OF DAMAGES IS PROVIDED, SUCH EXPRESS REMEDY OR MEASURE OF DAMAGES SHALL BE THE SOLE AND EXCLUSIVE REMEDY, THE OBLIGOR'S LIABILITY SHALL BE LIMITED AS SET FORTH IN SUCH PROVISION AND ALL OTHER REMEDIES OR DAMAGES AT LAW OR IN EQUITY ARE WAIVED. IF NO REMEDY OR MEASURE OF DAMAGES IS EXPRESSLY HEREIN PROVIDED, THE OBLIGOR'S LIABILITY SHALL BE LIMITED TO DIRECT ACTUAL DAMAGES ONLY, SUCH DIRECT ACTUAL DAMAGES SHALL BE THE SOLE AND EXCLUSIVE REMEDY AND ALL OTHER REMEDIES OR DAMAGES AT LAW OR IN EQUITY ARE WAIVED. UNLESS EXPRESSLY HEREIN PROVIDED, AND EXCEPT FOR THE PAYMENT OF LIQUIDATED DAMAGES SPECIFIED HEREIN, NEITHER PARTY NOR THEIR**

AFFILIATES SHALL BE LIABLE FOR ANY SPECIAL, CONSEQUENTIAL, INCIDENTAL, PUNITIVE, EXEMPLARY OR INDIRECT DAMAGES, OR LOSSES OR DAMAGES FOR LOST REVENUES OR LOST PROFITS OR OTHER BUSINESS INTERRUPTION DAMAGES, BY STATUTE, IN TORT OR CONTRACT, UNDER ANY INDEMNITY PROVISION OR OTHERWISE ; PROVIDED, HOWEVER, THAT THIS SENTENCE SHALL NOT APPLY TO LIMIT THE LIABILITY OF (1) AMOUNTS OWED TO THIRD PARTIES FOR WHICH A PARTY IS ENTITLED TO INDEMNIFICATION UNDER THIS AGREEMENT OR (2) A PARTY WHOSE ACTIONS GIVING RISE TO SUCH LIABILITY CONSTITUTE GROSS NEGLIGENCE OR WILLFUL MISCONDUCT; PROVIDED, FURTHER, THAT IT IS EXPRESSLY AGREED THAT THE LOST VALUE OF ANY INVESTMENT TAX CREDIT, PRODUCTION TAX CREDIT OR ANY OTHER SIMILAR TAX CREDIT OR BENEFIT WILL BE CONSIDERED CONSEQUENTIAL DAMAGES. TO THE EXTENT ANY DAMAGES REQUIRED TO BE PAID HEREUNDER ARE LIQUIDATED, THE PARTIES ACKNOWLEDGE THAT THE ACTUAL DAMAGES ARE DIFFICULT OR IMPOSSIBLE TO DETERMINE, OTHERWISE OBTAINING AN ADEQUATE REMEDY IS INCONVENIENT AND THE LIQUIDATED DAMAGES DO NOT CONSTITUTE A PENALTY AND ARE A REASONABLE APPROXIMATION OF THE HARM OR LOSS. NOTWITHSTANDING ANYTHING TO THE CONTRARY IN THIS AGREEMENT, IN NO EVENT SHALL BUYER'S LIABILITY TO SELLER FOR A TERMINATION PAYMENT UNDER THIS AGREEMENT EXCEED AN AMOUNT EQUAL TO THE SUM OF ANY AMOUNTS THEN OWED BY BUYER HEREUNDER PLUS THE TOTAL OF ALL REMAINING MONTHLY CAPACITY PAYMENTS FOLLOWING TERMINATION THAT WOULD

HAVE BEEN PAYABLE TO SELLER UNDER THIS AGREEMENT HAD THE AGREEMENT REMAINED IN EFFECT THROUGH THE END OF THE TERM.

WITHOUT PREJUDICE TO THE OBLIGATIONS AND LIABILITIES OF AN ENTITY PURSUANT TO ANY SELLER PERFORMANCE SECURITY, NEITHER ANY AFFILIATE OF A PARTY NOR ANY STOCKHOLDER, OFFICER, DIRECTOR, PARTNER, MEMBER OR EMPLOYEE OF A PARTY OR OF ANY AFFILIATE OF A PARTY (COLLECTIVELY, THE "NONRECOURSE PERSONS") SHALL HAVE ANY LIABILITY TO THE OTHER PARTY FOR THE PAYMENT OF ANY SUMS NOW OR HEREAFTER OWING BY SUCH PARTY OR FOR THE PERFORMANCE OF ANY OF THE OBLIGATIONS OF SUCH PARTY CONTAINED HEREIN, AND EACH OF THE PARTIES HERETO AGREES THAT ALL OF THE OBLIGATIONS OF THE OTHER PARTY UNDER THIS AGREEMENT SHALL BE OBLIGATIONS SOLELY OF SUCH OTHER PARTY AND RECOURSE IN ENFORCING SAID OBLIGATIONS SHALL ONLY BE HAD AGAINST THE ASSETS OF SUCH OTHER PARTY; PROVIDED THAT THE FOREGOING PROVISION SHALL NOT CONSTITUTE A WAIVER, RELEASE OR DISCHARGE OF ANY OF THE TERMS, COVENANTS OR CONDITIONS OF THIS AGREEMENT OR ANY SELLER PERFORMANCE SECURITY AND THE SAME SHALL CONTINUE UNTIL FULLY PAID, DISCHARGED, OBSERVED OR PERFORMED.

17.6 Disclaimer of Warranties. THERE ARE NO WARRANTIES UNDER THIS AGREEMENT EXCEPT TO THE EXTENT SPECIFICALLY SET FORTH IN THE TEXT HEREOF. THE PARTIES HEREBY SPECIFICALLY DISCLAIM AND EXCLUDE ALL IMPLIED WARRANTIES, INCLUDING THE IMPLIED WARRANTIES OF MERCHANTABILITY AND OF FITNESS FOR A PARTICULAR PURPOSE.

17.7 No Interruption. Except as otherwise provided in this Agreement, unless and until this

Agreement has been terminated, neither Party shall, as a result of any breach or alleged breach by the other Party, refuse to deliver, or suspend or delay any delivery of, capacity or associated energy to be provided under this Agreement; refuse to take energy to the extent required under this Agreement; suspend, delay or refuse to make, any of the payments required under this Agreement.

17.8 Duty to Mitigate. Notwithstanding any other provision of this Agreement, each Party has a duty to mitigate damages and covenants that it will use commercially reasonable efforts to minimize any damages it may incur as a result of the other Party's performance or non-performance.

ARTICLE 18

CHANGE OF LAW

18.1 New GHG Law.

18.1.1 In the event of the enactment of a New GHG Law by any Governmental Authority, Buyer shall reimburse Seller for the GHG Charges paid by Seller under such New GHG Law for Greenhouse Gas emitted due to the Facility or Alternate Resource producing and delivering energy pursuant to Schedule Instructions issued by Buyer; provided, however, that Seller shall be required to use GHG Credits, if any, to avoid or mitigate such GHG Charges in accordance with Section 18.1.3. In no event shall Buyer be responsible for GHG Charges associated with (i) Greenhouse Gas emissions that exceed the GHG Cap, or (ii) the operation of the Facility or Alternate Resource other than pursuant to Schedule Instructions issued by Buyer.

18.1.2 As a condition to Buyer's obligation to reimburse Seller for GHG Charges under Section 18.1.1, Seller shall submit to Buyer documentation of such GHG Charges that establishes each of the following to Buyer's reasonable satisfaction: (i) the amount of the GHG Charges; (ii) Seller is responsible for the payment of the GHG Charges to a Governmental Authority (or, in the case of an Alternate Resource, to a Person who is responsible to pay such Governmental Authority) in whose jurisdiction the Facility (or Alternate Resource) is located or that otherwise has jurisdiction over Seller or the Facility (or Alternate Resource) and Seller has paid the GHG Charges to the Governmental Authority (or other Person in the case of Alternate Resource); (iii) the GHG Charges were incurred for Greenhouse Gas emitted due to the Facility (or Alternate Resource) producing and delivering energy pursuant to Scheduling Instructions issued

by Buyer; and (iv) Seller took all reasonable steps to mitigate the cost or amount of such GHG Charges, including utilizing any GHG Credits specific to the Facility or the Seller pursuant to Section 18.1.3.

18.1.3 Seller shall be required to use GHG Credits allocated to or for the Facility, or otherwise granted to or received by Seller for the Facility, to avoid or mitigate GHG Charges otherwise reimbursable by Buyer under Section 18.1.1. In the event that Seller is allocated, issued, or has the right to obtain GHG Credits for a portion of or its entire fleet of generating units, then Seller shall, at no cost to Buyer, utilize a proportional amount of such GHG Credits to mitigate the GHG Charges otherwise reimbursable by Buyer under Section 18.1.1. For purposes of this Section 18.1.3, all references to "Seller" shall be deemed to include Seller's Affiliates or other entity to which GHG Credits may be or have been allocated to or given rights to obtain for the Facility. The proportional amount of GHG Credits shall be calculated based on the method, formula, or other similar calculation by which the Governmental Authority used to determine the amount of such GHG Credits attributable to each generating unit compared to the sum of all GHG Credits for all generating units of Seller. As a condition to Buyer's obligation to reimburse Seller for GHG Charges under Section 18.1.1, Seller shall provide Buyer with all information reasonably requested by Buyer to document GHG Credits and Seller's compliance with this Section 18.1.3.

18.1.4 Buyer shall be required to reimburse Seller for GHG Charges in respect of producing and delivering energy pursuant to Scheduling Instructions issued by Buyer from an Alternate Resource in accordance with Sections 18.1.1 and 18.1.2; provided, however, GHG Charges in respect of producing and delivering energy pursuant to Scheduling Instructions issued by Buyer from an Alternate Resource shall not exceed the GHG Charges that would have been assessed had the Facility produced and delivered such energy.

18.1.5 Seller shall not transfer, or provide any other Person rights with respect to, GHG Credits that Seller is required to use to mitigate GHG Charges under Section 18.1.3. If and to the extent that any GHG Credits for an Annual Period addressed by Section 18.1.3 are in excess of those required for the production of energy by the Facility to satisfy Buyer's Schedules for an Annual Period, then, Seller shall retain title to such GHG Credits and shall be entitled to use such GHG Credits for its own benefit.

18.2 Change of Law.

18.2.1 "Change of Law" means a Legal Requirement enacted after the Execution Date, which requires Seller to install additional or different equipment at the Facility or otherwise modify the Facility in order to comply with such Legal Requirement.

18.2.2 "Change of Law Capital Expenditures" means additional capital expenditures (determined in accordance with GAAP) reasonably incurred by Seller in accordance with Prudent Industry Practices for additional or different equipment installed at the Facility during the Term, or for other modifications to the Facility during the Term, as a direct result of a Change of Law and as necessary for the Facility as operated under this Agreement to comply with such Change of Law during the Term; provided, however, that capital expenditures will not constitute Change of Law Capital Expenditures unless Buyer, using Prudent Industry Practices, would incur the same capital expenditures with respect to its own generation facilities of the same type as the Facility as a result of the requirements of such Change of Law (taking into account differences in facility generating capacity and the frequency and duration of facility dispatch). Change of Law Capital Expenditures shall be appropriately pro-rated based on the remaining Term divided by the useful life of the applicable capital addition or modification. Change of Law Capital Expenditures will be net of any cost savings to Seller resulting from the capital addition or modification.

18.2.3 If Seller determines that any Change of Law Capital Expenditures will be incurred as a result of a Change of Law (including costs less than the Threshold Amount), Seller shall notify Buyer of a Change of Law by no later than six (6) Months after the enactment of the applicable Change of Law ("Change of Law Notice"). The Change of Law Notice must include a discussion of the relevant Change of Law, Seller's plan to comply with the Change of Law (including the additional or different equipment at the Facility or other modification of the Facility required to comply with the Change of Law), and reasonable documentation of Seller's determination of Change of Law Capital Expenditures (or estimate of Change of Law Capital Expenditures if actual costs are not known), and Seller will provide periodic updates to Buyer regarding Seller's compliance plan and Change of Law Capital Expenditures. Seller will provide any such additional relevant information as may reasonably requested by Buyer.

18.2.4 If one or more Change of Laws would cause Seller to incur Change of Law Capital Expenditures (in the aggregate) in excess of $1,000,000 in any given Annual Period (the "Threshold Amount"), and if Seller submitted a Change of Law Notice(s) for such Change of Law(s) pursuant to Section

18.2.3, then Seller may, through written notice to Buyer ("Excess Capital Expenditures Notice"), request Buyer's approval, in Buyer's sole discretion, of Seller's recovery of such incremental amount of capital expenditures in excess of the Threshold Amount (such excess amount, the "Excess Change of Law Capital Expenditures") through an adjustment to the Annual Capacity Price, provided that no adjustment will be allowed to a Annual Capacity Price for any Annual Period prior to Seller incurring Excess Change of Law Capital Expenditures. For purposes of calculating the adjustment to the Annual Capacity Price associated with capitalized additions or modifications to the Facility (determined in accordance with GAAP), the Parties will, each acting in good faith and in a commercially reasonable manner, establish an appropriate annual fixed charge rate for application to the original capital cost of such additions, modifications, or other capital expenditures. This calculation will represent the total cost associated with the identified addition or modification, including depreciation, carrying costs, and any other cost or expense item related to capital investments. Seller may not seek recovery of any Change of Law Capital Expenditures for which Seller did not submit a Change of Law Notice under Section 18.2.3. The Excess Capital Expenditures Notice shall supplement the Change of Law Notice, including addressing in detail the Excess Change of Law Capital Expenditures and setting forth Seller's calculations for the proposed increase in the Annual Capacity Price, as determined pursuant to this Section 18.2.4. Seller shall be responsible for demonstrating that Seller's proposed plan for complying with the Change of Law is reasonable and conforms with Prudent Industry Practices and that the Excess Change of Law Capital Expenditures are reasonable, consistent with Prudent Industry Practices, required for compliance with the Change of Law, and otherwise in compliance with Section 18.2. Seller shall promptly provide any and all other information reasonably requested by Buyer in connection Buyer's analysis of and response to Seller's Excess Capital Expenditures Notice.

18.2.5 By no later than three hundred sixty five (365) Days after receipt of Seller's Excess Capital Expenditures Notice, Buyer will inform Seller by written notice of whether Buyer, in Buyer's sole discretion, accepts or rejects Seller's proposed adjustment to the Annual Capacity Prices to recover Excess Change of Law Capital Expenditures ("Buyer Election Notice"); provided, however, if Buyer does not notify Seller of Buyer's decision within such three hundred sixty five (365) Day period, then Buyer will be deemed to have rejected Seller's proposed adjustment to the Annual Capacity Prices. For the avoidance of doubt, under no circumstances will Buyer's rejection of a proposed adjustment to Annual Capacity Prices and

Seller's recovery of Excess Change of Law Capital Expenditures constitute an Event of Default under Article 17 of this Agreement.

18.2.6 If Buyer, in its sole discretion, rejects Seller's request, or if Buyer is deemed under Section 18.2.5 to have rejected Seller's request, to recover Excess Change of Law Capital Expenditures addressed in Seller's Excess Capital Expenditures Notice, Seller shall provide written notice to Buyer (the "Seller Response Notice") by the Seller Response Deadline of whether Seller elects to (i) pay for such Change of Law Capital Expenditures (including Excess Change of Law Capital Expenditures), or (ii) terminate this Agreement effective as of the date set forth in the Seller Response Notice (which date shall be no earlier than three hundred sixty five (365) Days after the date the Seller Response Notice is provided to Buyer). The "Seller Response Deadline" is the date that is thirty (30) Days after the earlier of (i) the date of the Buyer Election Notice, or (ii) three hundred sixty-five (365) Days after Buyer's receipt of Seller's Excess Capital Expenditures Notice if Buyer did not provide a Buyer Election Notice. If Seller does not provide a Seller Response Notice to Buyer by the Seller Response Deadline, then Seller will be deemed to have waived such option to terminate this Agreement as a result of the relevant Change of Law(s) and Change of Law Capital Expenditures and shall be deemed to have elected to pay for such Change of Law Capital Expenditures (including Excess Change of Law Capital Expenditures). Notwithstanding anything herein to the contrary, if Seller elects to so terminate this Agreement in a Seller Response Notice provided to Buyer by the Seller Response Deadline, Buyer shall have the right to elect by written notice, delivered to Seller within sixty (60) Days after such Seller Response Notice, to accept Seller's proposed adjustment to Annual Capacity Prices as set forth in Seller's Excess Capital Expenditures Notice to recover Excess Change of Law Capital Expenditures, and in such case this Agreement shall not terminate and shall continue in full force and effect with such adjustment to Annual Capacity Prices. If Buyer does not provide such written notice within such sixty (60) Days period, then Buyer shall be deemed to have waived such election and this Agreement shall terminate in accordance with the Seller Response Notice on the date set forth in the Seller Response Notice (provided the termination date shall be no earlier than three hundred sixty five (365) Days after the date the Seller Response Notice is provided). Seller shall be responsible for all Change of Law Capital Expenditures incurred prior to the effective date of any such termination.

Following the effective date of any such termination, neither Party shall have any further liability to the other Party except for any obligations incurred prior to the effective date of the termination.

18.2.7 The Parties acknowledge that, except as provided in Sections 18.2.4, 18.2.5 and 18.2.6, the Annual Capacity Prices shall not be adjusted as a result of a Change of Law or Change of Law Capital Expenditures. If Buyer has elected under Section 18.2.5 or Section 18.2.6 to accept Seller's proposed adjustment to Annual Capacity Prices to recover Excess Change of Law Capital Expenditures, Seller may not seek any additional adjustment to Annual Capacity Prices for the same Change of Law(s) addressed in such Buyer election (including for any additional or different Change of Law Capital Expenditures arising from such Change of Law(s)). For the avoidance of doubt, any election by Buyer under Section 18.2.5 or Section 18.2.6 to allow Seller to recover Excess Change of Law Capital Expenditures shall apply only to the Change of Law and Excess Change of Law Capital Expenditures addressed in such Buyer election.

18.2.8 Seller acknowledges and agrees that except as provided in Article 18: (i) Buyer shall not be responsible for any costs or expenses incurred by Seller in connection with the Facility or the performance of Seller's obligations under this Agreement that result from new or different or other changes in Legal Requirements (including any change in an interpretation of any Legal Requirement); and (ii) in no event shall the payments required to be made by Buyer under this Agreement be increased as a result of any costs or expenses that Seller incurs as a result of new or different or other changes in Legal Requirements (including any change in an interpretation of any Legal Requirement).

18.3 No Dedication. No undertaking by Seller under this Agreement is intended to constitute the dedication of the Facility or any part thereof to the public or affect the status of Seller as an independent entity and not a public utility or public service company.

ARTICLE 19

ASSIGNMENT AND TRANSFERS OF INTERESTS

19.1 Assignment; Change in Control.

19.1.1 Subject to Sections 19.1.2 and 19.1.4, neither this Agreement nor any of the rights or obligations hereunder may be assigned by either Party without the express prior written consent of the

other Party, which consent shall not be unreasonably withheld, conditioned or delayed. Any attempted assignment that is not permitted under the terms of this Agreement shall be null and void *ab initio*.

19.1.2 Seller may, without the consent of Buyer, assign this Agreement to a lender for collateral security purposes in connection with any financing or the refinancing of the Facility, and in connection therewith, Buyer agrees to execute a reasonable written consent to such collateral assignment in a form acceptable to Buyer should the financing party reasonably request such consent; provided, however, that such collateral assignment shall not expand the liability, risks or obligations imposed on Buyer under this Agreement.

19.1.3 Estoppels Related to Financing or Purchases of Interest. Upon reasonable request to Buyer, Buyer agrees to execute a written confirmation that, if true, then to the best of Buyer's knowledge at the time of the Request, Seller is not in default of this Agreement.

19.1.4 Buyer agrees that Seller may assign this Agreement and all or any portion of its rights, responsibilities and interests under, in and to this Agreement to any purchaser or assignee of the Facility (including an Affiliate) or of all or substantially all of the Facility assets without the consent of Buyer; provided, however, *that* such assignee (i) provides to Buyer consistent with the provisions of Article 7 hereof, Seller Performance Security in an amount equal to the Eligible Collateral Amount, (ii) executes an assumption agreement pursuant to which such assignee shall assume all the obligations of Seller under this Agreement, and agree to be bound by all the terms and conditions of this Agreement, (iii) is, or contracts for the operation of the Facility with, a Qualified Operator, (iv) has the legal power and authority to perform and satisfy the obligations of the Seller under this Agreement and (v) has delivered to Buyer's reasonable satisfaction information reasonably requested by Buyer for purposes of its applicable "know-your-customer" procedures. Upon any such assignment, Seller shall be relieved of and fully discharged from its obligations hereunder that arise from and after the assignment date, to the extent assumed by the assignee in writing. Seller will notify Buyer in writing as soon as reasonably practicable prior to any assignment made pursuant to this Section 19.1.4.

19.1.5 Any direct or indirect Change of Control of Seller (by voluntary transfer or by operation of law) shall not require the prior consent Buyer, *provided that* the entity acquiring ownership of Seller meets the requirements set forth in Section 19.1.4(i), (iii) and (v), and *provided further* that (i) the

Person acquiring Control of Seller may satisfy the requirements set forth in Section 19.1.4(i) by maintaining or causing Seller to maintain Seller Performance Security in accordance with Article 7 and (ii) Buyer shall promptly request information for purposes of its applicable "know-your-customer" procedures under Section 19.1.4(v) no later than 10 Days after receiving written notice of a potential Change of Control by Seller. Seller will notify Buyer in writing as soon as reasonably practicable prior to any Change of Control by Seller pursuant to this Section 19.1.5.

19.2 Buyer. Buyer may not assign this Agreement or any portion thereof to any Person other than a Creditworthy Affiliate without the prior written consent of Seller.

19.3 Reimbursement for Buyer's Costs from Transfers or Assignments. Seller agrees that, in the event Seller assigns or transfers an interest in the Facility or the Agreement, as such transactions are described in Section 19.1 and Section 19.2, Seller shall pay Buyer the amount of twenty-five thousand dollars ($25,000.00) per occurrence for each and any proposed transaction and will pay to Buyer the amount of ten thousand dollars ($10,000) per occurrence for each and any request for an estoppel pursuant to Section 19.1.1.3. For the avoidance of doubt, if Seller requests Buyer's consent under Section 19.1.1 or Section 19.2, and Buyer undertakes drafting of consent documents or amendments to provide such consent, and Seller thereafter fails to consummate the proposed transaction, Buyer reserves the right, in its sole discretion, to require Seller to provide reimbursement to Buyer pursuant to this Section 19.3.

19.4 General Requirements. Any consent required by Sections 19.1 or 19.2 shall not be unreasonably withheld, conditioned, or delayed; provided, however, that neither Party shall be required to consent to any limitation of its rights under this Agreement or expansion of the liability, risks or obligations imposed on it under this Agreement (including changes in accounting treatment). It shall be reasonable for either Party to condition any consent required by Article 19 on the execution of amendments to this Agreement that are reasonably determined by such Party to be necessary to preserve the value and protection afforded to such Party under this Agreement. It shall be a condition of any assignment, transfer, Change of Control Transaction or other disposition with respect to this Agreement and/or the Facility under Section 19.1.1 or 19.2 for which consent is required that Seller Performance Security required under Section 7.1, if applicable, shall remain in place notwithstanding such disposition, or that replacement security in form, substance and amount in full compliance with this Agreement or otherwise reasonably

acceptable to Buyer shall have been provided prior to such disposition. Any purported assignment, transfer, Change of Control or other disposition with respect to this Agreement and/or the Facility that is not in compliance with the applicable provisions of Section 19.1 or Section 19.2, as the case may be, will be null and void, and of no force and effect.

ARTICLE 20

DISPUTE RESOLUTION

20.1 Notice of Dispute; Dispute Resolution Process. Either Party ("Disputing Party") has the right to give notice to the other Party ("Responding Party") that the Responding Party is not performing in accordance with the terms and conditions of this Agreement. Such notice (the "Notice of Dispute") will describe with specificity the basis for the Disputing Party's belief and may propose a resolution of such dispute. Within fifteen (15) Business Days after receiving the Notice of Dispute, the Responding Party will provide the Disputing Party with a written response to the Notice of Dispute, which will describe with specificity the basis for the Responding Party's position and which may include additional issues (if any) with respect to the dispute raised by the Notice of Dispute and may propose a resolution of such dispute (the "Dispute Response"). Within five (5) Business Days after the submission of the Dispute Response, the dispute will be submitted to a designated senior Representative of Seller and a designated senior Representative of Buyer for resolution. If the designated senior Representatives are unable to resolve the dispute to the mutual satisfaction of the Parties within twenty (20) Business Days from the submission to such designated senior Representatives, or such other period as the Parties may agree upon, then (a) in the case of disputes described in Section 20.2, either Party may provide written notice to the other Party declaring an impasse (the "Impasse Notice") and thereafter the Parties agree to arbitrate such disputes pursuant to Section 20.2, (b) in the case of disputes described in Section 20.3, either Party may provide an Impasse Notice and thereafter the Parties agree to arbitrate such disputes pursuant to Section 20.3, and (c) in the case of any dispute that is not described in Section 20.2 or Section 20.3, either Party may pursue such rights and remedies as may be available under applicable law or in equity subject to the terms and conditions of this Agreement.

20.2 Expert Arbitration. Upon the submission of an Impasse Notice, a dispute with respect to

(a) the results of a Performance Test (under any provision of this Agreement), (b) a Capacity Shortfall (Section 5.1.7), (c) Imbalance Charges (Section 12.2.5), (d) Seller Event of Default under Sections 17.1.8 or 17.1.9, or (e) the development of Maintenance Schedules (Section 11.2.1) shall be resolved by arbitration as set forth in this Section 20.2.

20.2.1 Selection of Expert. The Parties shall attempt to agree upon the selection of an independent third-party expert to make a determination concerning such dispute. If the Parties are unable to mutually agree on the selection of an expert within fifteen (15) Days following the submission of the Impasse Notice, the Disputing Party shall provide a list of five (5) qualified experts to the Responding Party and the Responding Party shall select one expert from such list. As a condition to appointment as a qualified expert, the expert must satisfy the following criteria: (i) be competent and experienced in matters involving the electric energy business in the United States, with at least ten (10) years of experience in the electric industry; (ii) have no interest, financial or otherwise, in either Party or this Agreement beyond payment of the fees and expenses for serving as the expert hereunder; and (iii) have not performed, or been employed by a firm that has provided, services for either Party, and otherwise have not been previously or currently employed or engaged in any capacity by, and not have a personal or professional relationship with, either Party other than as the expert hereunder, unless such employment, engagement or relationship has been disclosed in writing to the Parties prior to the appointment as an expert hereunder. The expert must not advise or otherwise communicate ex parte in any way with either Party following appointment as an expert hereunder and must treat the details of this Agreement and all expert activity hereunder as private and confidential, and not publish or disclose any information related to the arbitration without the prior written consent of both Parties.

20.2.2 Expert Decision. Within fifteen (15) Days after the selection of the expert, the Parties shall file with the expert written positions (with supporting documentation) concerning the dispute. The expert may request additional filings and shall render a decision within fifteen (15) Days of receipt of all filings. In the case of any dispute resolved under this Section 20.2, the decision rendered by the independent expert shall be final and binding upon Seller and Buyer. Following the resolution of a dispute hereunder involving the Designated Capacity, Monthly Capacity Payment billing shall (if necessary and as soon as practicable) be adjusted retroactively (with interest at the Interest Rate) to reflect Designated

Capacity equal to such expert's determination.

20.2.3 Costs. In the event the independent expert adopts the position of one of the Parties, then the other Party shall pay the fees and expenses of such expert. Otherwise, such fees and expenses will be shared equally by the Parties.

20.3 JAMS Arbitration. Upon the submission of an Impasse Notice, (a) a dispute with respect to the calculation of a Termination Payment pursuant to Section 17.3.3, or (b) a billing dispute under Section 6.2.2, including a dispute concerning the calculation of (i) a Monthly Capacity Payment pursuant to **Appendix A**, Sections B, C and D, or (ii) a Monthly Energy Payment pursuant to **Appendix B**, shall be resolved by arbitration as set forth in this Section 20.3.

20.3.1 JAMS. Such billing dispute (the "Claim") will be resolved under the Federal Arbitration Act by binding arbitration following the JAMS Comprehensive Arbitration Rules and Procedures (the "Rules") of Judicial Arbitration and Mediation Services ("JAMS") then in effect, including its evidentiary and procedural rules, except as modified herein. It is the Parties' intent that such arbitration, including the selection and qualification of arbitrators, will be conducted in accordance with the Rules, as amended and supplemented, except where specifically modified by this Agreement, and not by the terms of any state arbitration act or other Legal Requirement.

20.3.2 Initiation of Arbitration; Selection of Arbitrators.

20.3.2.1 Within ten (10) Business Days after delivering an Impasse Notice, the delivering Party must contact JAMS to commence arbitration and must provide written notice to the other Party in accordance with Section 21.4. Arbitration will be deemed to be commenced when JAMS issues a Commencement Letter (as defined in the Rules) in accordance with the Rules. The Party initiating arbitration will nominate one (1) arbitrator at the same time it initiates arbitration. The other Party will nominate one (1) arbitrator within ten (10) Business Days of receiving the Commencement Letter. The two Party-nominated arbitrators will be deemed neutrals and not the representative of the appointing Party. The two (2) arbitrators (the "Party-Appointed Arbitrators") will appoint a third arbitrator (the "Third Arbitrator"). All arbitrators will (i) be competent and experienced in matters involving the electric energy business in the United States, with at least ten (10) years of legal, engineering, or business experience in the electric industry; (ii) have no interest, financial or otherwise, in the Parties or this Agreement beyond payment of

their fees and expenses for serving on the Arbitration Panel; and (iii) have not performed, or been employed by a firm that has provided, services for either Party, and otherwise have not been previously or currently employed or engaged in any capacity by, and not have a personal or professional relationship with, either Party other than as a member of the Arbitration Panel, unless such employment, engagement or relationship has been disclosed in writing to all Parties prior to the selection of the Arbitration Panel. Arbitrators must not advise or otherwise communicate ex parte in any way with either Party following appointment to the Arbitration Panel and must treat the details of this Agreement and all Arbitration Panel activity as private and confidential, and not publish or disclose any information related to the arbitration without the prior written consent of both Parties. Further, the Third Arbitrator will be independent of the Parties and the Party-Appointed Arbitrators. Each Party will pay the fees and expenses incurred by its Party-Appointed Arbitrator and the fees and expenses of the Third Arbitrator will be divided equally between the Parties.

20.3.2.2 If the Party-Appointed Arbitrators are unable to agree on the Third Arbitrator within ten (10) Business Days from initiation of arbitration, then the Third Arbitrator will be selected by JAMS with due regard given to the selection criteria in Section 20.3.2.1 and input from the Parties and the Party-Appointed Arbitrators. Parties will undertake to request JAMS to complete selection of the Third Arbitrator no later than sixty (60) Days from initiation of arbitration. Costs charged by JAMS for this service will be borne by the Parties equally. If JAMS should fail to select the Third Arbitrator within sixty (60) Days from initiation of arbitration, then either Party may petition a court of competent jurisdiction in Atlanta, Fulton County, Georgia to select the Third Arbitrator. Due regard will be given to the selection criteria in Section 20.3.2.1 and input from the Parties and the Party-Appointed Arbitrators.

20.3.2.3 If prior to the conclusion of the arbitration any member of the Arbitration Panel becomes incapacitated or otherwise unable to serve, then a replacement arbitrator will be appointed in the manner set forth in this Section 20.3.2.

20.3.3 Discovery; Hearing. Discovery and other pre-hearing procedures will be conducted as agreed by the Parties, including at least one corporate representative deposition, or if they cannot agree, as determined by a majority of the Arbitration Panel; provided, however, all pre-hearing discovery will be completed within ninety (90) Days following selection of the Third Arbitrator. Within fifteen

(15) Business Days after completion of such pre-hearing discovery, each Party will submit, either individually or jointly, by overnight delivery to the other Party and the Arbitration Panel a separate, precise statement for each issue in dispute, that Party's proposed means of resolving each issue, and the factual or legal support for such proposal (the "Proposed Resolutions"). No later than thirty (30) Business Days after all pre-hearing discovery has been completed, a hearing will be conducted at which Seller and Buyer will each present such evidence and witnesses as it may choose. Arbitration will be conducted in accordance with the Rules, as amended and supplemented, except where specifically modified by this Agreement.

20.3.4 Confidential Proceeding. Each Party will maintain the confidentiality of the arbitration proceedings, except as reasonably necessary to effectively represent itself in the proceeding to enforce the arbitration award or determination, or as otherwise required by law. All discovery materials will remain confidential pursuant to Section 21.13.

20.3.5 Arbitration Cost. Each Party will be responsible for its own legal and arbitration expenses incurred in connection with the arbitration proceeding, including attorneys' fees, investigation or discovery (including e-discovery) costs, and expert, consultant or arbitrator fees and expenses.

20.3.6 Arbitrator Decisions.

20.3.6.1 The Arbitration Panel will consider the terms and conditions of this Agreement, including all relevant evidence and testimony, and will render its decision within thirty (30) Days following conclusion of the hearing by means of a written reasoned decision; provided, however, the Arbitration Panel is expressly and specifically limited to selecting one (1) of the Proposed Resolutions provided by Seller and Buyer for each issue in dispute. The Arbitration Panel will have no authority to award consequential, special, indirect, treble, exemplary, incidental, or punitive damages of any type under any circumstance, regardless of whether such damages may be available under applicable state law, federal law, the Federal Arbitration Act, or any other applicable law.

20.3.6.2 The written decision rendered by a majority of the Arbitration Panel will be provided to the Parties. Each Party will indicate its acceptance or rejection of the decision by notifying the opposing Party within ten (10) Days after issuance of the decision. If both Parties accept such decision, such decision may be filed in a court of competent jurisdiction and may be enforced by Seller or

Buyer as a final judgment in such court. If either Party rejects the written decision, the rejecting Party may pursue any avenue of appeal pursuant to the Federal Arbitration Act; provided, however, that no Party will recover consequential, special, indirect, treble, exemplary, incidental, or punitive damages.

20.4 Location of Arbitration. Any arbitration under Section 20.2 or Section 20.3 will take place in Atlanta, Fulton County, Georgia.

20.5 Mandatory Arbitration. SUBJECT TO SECTION 20.3.6.2, EACH PARTY UNDERSTANDS AND AGREES THAT WHEN ARBITRATION IS REQUIRED UNDER THIS ARTICLE 20, ARBITRATION IS MANDATORY AND EACH PARTY WAIVES ANY RIGHT TO SEEK JUDICIAL RELIEF OR FILE COURT PROCEEDINGS TO DETERMINE THE SPECIFIED MATTERS UNDER SECTION 20.2 OR SECTION 20.3, OTHER THAN THE RIGHT TO SEEK JUDICIAL RELIEF TO COMPEL ARBITRATION, TO CONFIRM AN ARBITRATION AWARD, OR TO SEEK INJUNCTIVE RELIEF PURSUANT TO SECTION 20.6 IN ACCORDANCE WITH THIS AGREEMENT.

20.6 Injunctive Relief. Notwithstanding any other provision of this Article 20, the Parties acknowledge that an award of damages may not afford complete relief or furnish an adequate legal remedy as between them (such as when Seller's Event of Default arises from Seller's actions designed to achieve an economic gain by selling energy, capacity or Ancillary Services to a third party in violation of this Agreement). Accordingly, the Parties agree that a Party will be permitted to seek at any time, in accordance with applicable laws, procedures, and the terms of this Agreement, injunctive relief relating to the performance of this Agreement from an arbitrator, a Governmental Authority of appropriate jurisdiction, or a court of competent jurisdiction located in Atlanta, Fulton County, Georgia. The Parties expressly agree that this Section 20.6 does not present a question of substantive arbitrability and waive any right to have an arbitrator decide whether preliminary injunctive relief is available in court. In the event of entry of any interlocutory injunctive relief, the Party against whom such relief is entered waives the right to have a bond or security posted pending resolution of the dispute giving rise to the issuance of the injunction.

20.7 Continued Performance. The Parties agree to continue performing their respective obligations under this Agreement while the dispute is being resolved, unless and until such obligations are terminated or expire in accordance with the provisions of this Agreement.

ARTICLE 21

MISCELLANEOUS PROVISIONS

21.1 Amendments. This Agreement may be amended only by a written instrument duly executed by authorized representatives of Buyer and Seller.

21.2 Binding Effect. This Agreement and any extension shall inure to the benefit of and shall be binding upon the Parties and their respective permitted successors and assigns.

21.3 Counterparts. This Agreement may be executed by electronic means (PDF) and in several counterparts, each of which shall be an original and all of which shall constitute a single instrument.

21.4 Notices. Unless otherwise specified, where notice is required by this Agreement, such notice shall be in writing and shall be deemed given: (i) upon receipt, when mailed by United States registered or certified mail, postage prepaid, return receipt requested; or (ii) upon the next Business Day, when sent by overnight delivery, postage prepaid using a nationally recognized courier service. In all instances, notice to the respective Parties should be directed as follows:

To Seller:

Santa Rosa Energy Center, LLC
c/o LS Power Development, LLC
Attn: General Counsel
1700 Broadway, 35th Floor
New York, NY 10019
Fax: 212-547-2866

With copies to

Santa Rosa Energy Center, LLC
c/o LS Power Development, LLC
Attn: Legal Department
One Tower Center, 21st Floor
East Brunswick, NJ 08816-1100
Fax: 732-249-7290

To Buyer:

Georgia Power Company
241 Ralph McGill Blvd NE
BIN 10194
Atlanta, GA 30308
Attn: Director of Resource Policy & Planning
Telephone: (404) 506-2568
Email: jrgrubb@southernco.com

with copies to:

Georgia Power Company Legal Dept.
241 Ralph McGill Blvd., N.E.
Bin 10180
Atlanta, GA 30308
Attn: Commercial & Transactional Counsel
Telephone: (404) 506-5358
Email: ctwingfi@southernco.com

or to such other addressees as may later be designated by the Parties.

21.5 Entire Agreement. This Agreement (including the attached **Appendices**) constitutes the

entire understanding between the Parties and supersedes any previous agreements related to the subject matter hereof between the Parties. The Parties have entered into this Agreement in reliance upon the representations and mutual undertakings contained herein and not in reliance upon any oral or written representations or information provided by one Party to the other Party not contained or incorporated herein.

21.6 Governing Law. This Agreement shall be governed by and construed in accordance with the laws of the state of Georgia, without giving effect to any conflict of law rules thereof, which may direct the application of the laws of another jurisdiction. With respect to those matters that may be referred to the state or federal courts under this Agreement, the Parties agree to submit to the exclusive jurisdiction of either the Fulton County Superior Court in Atlanta, Georgia or the U.S. District Court for the Northern District of Georgia, Atlanta Division, as appropriate.

21.7 Time of Essence; Waiver.

21.7.1 Time is of the essence in the performance of obligations pursuant to this Agreement.

21.7.2 The failure of either Party to enforce at any time any of the provisions of this Agreement, or to require at any time performance by the other Party of any of the provisions hereof, shall in no way be construed to be a waiver of such provisions, or in any way to affect the validity of this Agreement or any part hereof or the right of such Party hereafter to enforce every such provision. No modification or waiver of all or any part of this Agreement shall be valid unless it is reduced to a writing, signed by both Parties, that expressly states that the Parties agree to a waiver or modification, as applicable.

21.8 Headings. The headings contained in this Agreement are used solely for convenience and do not constitute a part of the Agreement between the Parties, nor should they be used to aid in any manner in the construction of this Agreement.

21.9 Third Parties. This Agreement is intended solely for the benefit of the Parties hereto. Nothing in this Agreement shall be construed to create any duty, standard of care or liability to any Person not a Party to this Agreement.

21.10 Agency. This Agreement shall not be interpreted or construed to create an association, joint venture, or partnership between the Parties or to impose any partnership obligation or liability upon

either Party. Neither Party shall have any right, power or authority to enter into any agreement or undertaking for, or act on behalf of, or to act as or be an agent or representative of, or to otherwise bind, the other Party.

21.11 Severability. If any term or provision of this Agreement or the application thereof to any Person, entity, or circumstance shall to any extent be invalid or unenforceable, the remainder of this Agreement, or the application of such term or provision to Persons, entities or circumstances other than those as to which it is invalid or unenforceable, shall not be affected thereby, and each term and provision of this Agreement shall be valid and enforceable to the fullest extent permitted by law.

21.12 Negotiated Agreement. This Agreement shall be considered for all purposes as prepared through the joint efforts of the Parties and shall not be construed against one Party or the other as a result of the preparation, substitution or other event of negotiation, drafting or execution hereof.

21.13 Confidentiality.

21.13.1 The Parties acknowledge that portions of this Agreement contain Confidential Information and may require the Parties to disclose additional Confidential Information to one another. Each Party agrees that: (i) for a period of three (3) years from the date hereof for Confidential Information contained in this Agreement; and (ii) for a period of three (3) years from the date of disclosure for additional Confidential Information disclosed during the Term, it will not, and will ensure that none of its Affiliates, consultants or advisors do not, without the written consent of the other Party or as otherwise provided herein, disclose to any third party (other than to (i) Affiliates of the disclosing Party or to consultants and advisors to such Affiliates and the disclosing Party who need to know such information in connection with the performance of their duties or services for such Affiliates or the disclosing Party; (ii) the operator of the Facility in connection with its performance of services related to the Facility; or (iii) Lenders, investors, financing parties or potential acquirors of Seller or the Facility, in each case for which a Party will be responsible for any breach of these provisions by such Person), such portions of this Agreement, or the terms or provisions hereof, or any additional Confidential Information disclosed pursuant to such Party's performance of this Agreement and identified as Confidential Information at the time of such disclosure, except to the extent that disclosure to a third party is required by law, or by a court or by an administrative agency having jurisdiction over the disclosing Party.

21.13.2 Buyer agrees to seek confidential treatment of the Confidential Information in this Agreement from the GPSC, but acknowledge that certain terms, conditions, and provisions of this Agreement will need to be disclosed in connection with the application for a the GPSC Certificate. No assurance or commitment is made regarding the ability of Buyer to obtain the requested confidential treatment in that proceeding or otherwise.

21.13.3 The Parties agree to seek confidential treatment of the Confidential Information in this Agreement from FERC but acknowledge that certain Confidential Information may be made publicly available by FERC.

21.13.4 Any public statement or other announcement by a Party hereto concerning the transaction described herein shall be reviewed and agreed upon by the Parties before release, which agreement shall not be unreasonably withheld, conditioned or delayed.

21.14 Interpretation. In this Agreement, unless the context otherwise requires, the singular shall include the plural and any pronoun shall include the corresponding masculine, feminine and neuter forms. The words "hereof," "herein," "hereto" and "hereunder" and words of similar import when used in this Agreement shall, unless otherwise expressly specified, refer to this Agreement as a whole and not to any particular provision of this Agreement. Whenever the term "including" is used herein in connection with a listing of items included within a prior reference, such listing shall be interpreted to be illustrative only, and shall not be interpreted as a limitation on or exclusive listing of the items included within the prior reference. Any reference in this Agreement to "Section," "Article," or "Appendix" shall be references to this Agreement unless otherwise stated, and all such Appendices shall be incorporated into this Agreement by reference. Unless specified otherwise, a reference to a given agreement or instrument, and all schedules, exhibits, appendices and attachments thereto, shall be a reference to that agreement or instrument as modified, amended, supplemented and restated, and in effect from time to time. Unless otherwise stated, any reference in this Agreement to any entity shall include its permitted successors and assigns, and in the case of any Governmental Authority, any Person succeeding to its functions and capacities.

21.15 Replacement Index. Should any index or tariff referenced in this Agreement be discontinued, no longer published or deemed unrepresentative, the Parties will cooperate in establishing substitute benchmarks through reference to equivalent indices or tariffs.

21.16 Recording. Each Party acknowledges and consents to the tape or electronic recording of all telephone conversations between the Parties, and that any such recordings will be retained in confidence, secured from improper access, and may be submitted in evidence in any proceeding or action relating to this Agreement. Each Party waives any further notice of such monitoring or recording, and agrees to notify its officers and employees of such monitoring or recording and to obtain any necessary consent of such officers and employees.

21.17 Further Assurances. The Parties agree to provide such reasonable cooperation to each other as necessary to give effect to the terms of this Agreement.

21.18 Transfer of Information Acknowledgement. Seller agrees to execute contemporaneous with the execution of this Agreement, the Transfer of Information Acknowledgement attached as **Appendix N**, and Buyer agrees to the limited use and confidential treatment of such information a set forth in **Appendix N**.

[The next page is the signature page.]

IN WITNESS WHEREOF, the Parties have caused this Agreement to be executed by their duly authorized officers, as of the date first above written.

GEORGIA POWER COMPANY ("BUYER")

By: _____

Name: Rick Anderson

Title: SVP and SPO - East

SANTA ROSA ENERGY CENTER LLC ("SELLER")

By: _____

Name: _____

Title: President

APPENDIX A

CAPACITY; CAPACITY PAYMENT

A. **Contracted Capacity; Tested Reliable Capacity; Designated Capacity; Capacity Buy Down; Capacity Pricing:**

1. **Contracted Capacity Cap; Contracted Capacity Range:** The "Contracted Capacity Cap" shall equal 102.5% of the Nominal Capability, provided that Buyer, in its sole discretion, may elect to accept an offer from Seller to increase the Contracted Capacity Cap to an amount equal to a Tested Reliable Capacity that is greater than 102.5% of the Nominal Capability pursuant to Section A.2 of this **Appendix A**.

Subject to Section A.4 of this **Appendix A**, the upper limit of the Contracted Capacity range for the Term shall be the Contracted Capacity Cap. Subject to Section A.4 of this **Appendix A**, the lower limit of the Contracted Capacity range for the Term shall be ninety-two percent (92%) of the Nominal Capability.

2. **Tested Reliable Capacity; Performance Tests:**

The Parties agree that the Designated Capacity in Section 3 of Appendix A will establish the initial Tested Reliable Capacity. Following the establishment of the initial Tested Reliable Capacity hereunder, each Party shall have the right to request a Performance Test to re-determine the Tested Reliable Capacity to be performed during the period from March 15 to April 15 of each Annual Period upon ten (10) Business Days written notice to the other Party; provided, however, that upon consent by both Parties, such Performance Test may be performed outside the period of March 15 to April 15 of each Annual Period; provided, further that no such Performance Test may be scheduled during any period of Scheduled Outage, Maintenance Outage, Force Majeure Event or during a Forced Outage. The Tested Reliable Capacity determined as a result of an additional Performance Test shall become the new Tested Reliable Capacity.

In the event a Performance Test results in a Tested Reliable Capacity that is greater than the then-effective Contracted Capacity Cap, Seller may offer to increase the Contracted Capacity Cap to such Tested Reliable Capacity and Buyer shall accept or reject such offer, in its sole discretion. If Buyer accepts such offer, then the Contracted Capacity Cap shall be reset to the Tested Reliable Capacity resulting from such Performance Test. If Buyer does not accept such offer, the Contracted Capacity Cap shall not change.

For all subsequent Performance Tests, the requesting Party shall bear the costs and expenses of such subsequent Performance Test; provided, however, that Seller shall bear such costs and expenses of (i) any Performance Test requested by Buyer if the Tested Reliable Capacity (as a result of such Performance Test) is determined to be less than the Tested Reliable Capacity immediately prior to such Performance Test, or (ii) any Performance Test performed under Section 4 of this **Appendix A**, or (iii) any Performance Test performed due to a reliability issue pursuant to Section 3 of **Appendix D**. If Buyer is responsible for the fuel costs for a Performance Test, Buyer will purchase test energy at the applicable price under **Appendix B** for energy delivered from the Facility pursuant to Buyer's Schedule. If Seller is responsible for the fuel costs for a Performance Test, Buyer will purchase test energy at the applicable price under **Appendix B** for energy delivered from the Facility pursuant to Buyer's Schedule.

3. **Designated Capacity:** The Designated Capacity for the balance of the first annual period will be 215 MW for the months of May through October and 230 MW April, November, and December.

For all subsequent annual periods, the Designated Capacity for May through October will be 215 MW and for November through April will be 230 MW unless Seller designates a Designated Capacity that is less than the Tested Reliable Capacity as set forth below in this Section A.3 of **Appendix A**, the Designated Capacity shall be deemed to be the Tested Reliable Capacity, respectively; provided, however, notwithstanding anything herein to the contrary, the Designated Capacity shall not exceed the Contracted Capacity Cap, respectively. If the Tested Reliable Capacity under a Performance Test is greater than the then-effective Contracted Capacity Cap and Seller does not offer, or Buyer rejects an offer, to increase the Contracted Capacity Cap to such Tested Reliable Capacity under Section A.2 of this **Appendix A**, then the Designated Capacity shall be deemed to be the Contracted Capacity Cap unless Seller designates a Designated Capacity that does not exceed the Contracted Capacity Cap, respectively, as set forth below in this Section A.3 of **Appendix A**.

Within ten (10) Business Days of establishment of the Tested Reliable Capacity through a Performance Test, Seller may elect by written notice to Buyer to designate a Designated Capacity that is less than the Tested Reliable Capacity, respectively, resulting from such Performance Test; provided, however, that, (i) such Designated Capacity shall not exceed the Contracted Capacity Cap, respectively, and (and (iii) if Seller does not so designate a Designated Capacity in such ten (10) Business Days period, the Designated Capacity shall be determined as set forth above in this Section A.3 of **Appendix A**.

However, notwithstanding anything herein to the contrary, in the event the Interconnection Agreement requires Seller to produce reactive power for the Florida Power and Light Company Transmission System, the Designated Capacity shall not exceed the capability of the Facility assuming that the maximum production of reactive power is being supplied to satisfy the Interconnection Agreement requirements.

Any change to the Designated Capacity shall take effect on the first day of the next Month after such new Designated Capacity is determined and designated in accordance with this Section A.3.

Notwithstanding anything herein to the contrary, this Section A.3 of **Appendix A** is subject to the determination of a Capacity Shortfall pursuant to Section 5.1.7.

4. **Tested Reliable Capacity Below Contracted Capacity Range; Capacity Buy Down:** In addition to and without limiting the remedies available to Buyer pursuant to Section 17.1.9, if a Performance Test indicates that the Facility's Tested Reliable Capacity is less than the lower end of the then-effective Contracted Capacity range but greater than or equal to seventy percent (70%) of the Nominal Capability or any other percentage if Buyer makes the election provided under Section 17.1.9.3: Seller shall have ten (10) Days to submit to Buyer a cure plan for increasing the Facility's capacity which shall be reasonably acceptable to Buyer and shall include a reasonable cure period during which Seller may conduct additional Performance Tests. Such cure period shall not exceed one hundred twenty (120) Days; provided, however, if Seller establishes a cure plan hereunder but requires a cure period of more than one hundred twenty (120) Days to cure the inadequate Tested Reliable Capacity, then such cure period will be extended for a reasonable additional period of time, which extension will not in any case exceed four hundred twenty (420) Days, provided that Seller satisfies all of the following conditions to any such extension: no later than fifteen (15) Days prior to the expiration of the one hundred twenty (120) Days cure period, Seller shall provide to Buyer (i) a revised cure plan setting forth a reasonable extension of the cure period, not to exceed four hundred and twenty (420) Days, which revised cure plan and extension shall be reasonably acceptable to Buyer, and (ii) a written certification reasonably acceptable to Buyer confirming that in order for Seller to cure the inadequate Tested Reliable Capacity Seller must be afforded such reasonable additional period of time, and (iii) Seller's election for the period of such extended cure period to cover (to the extent of the degraded capacity) Buyer's Schedules through an Alternate Resource in accordance with Section 5.1.4.3. For the avoidance of doubt, the total duration of any such cure period, as extended, shall not exceed five hundred and forty (540) Days. The inadequate Tested Reliable Capacity shall be deemed cured under this Section 4 of

Appendix A only if (i) Seller provides Buyer with a written certification reasonably acceptable to Buyer confirming that the inadequate Tested Reliable Capacity has been cured, and (ii) the Tested Reliable Capacity, as demonstrated by the most recent Performance Test, is increased to a value equal to or greater than the lower limit of the original Contracted Capacity range as set forth in Section 1 of this **Appendix A**. Throughout the duration of any cure period, the Designated Capacity will be deemed to be the Tested Reliable Capacity determined pursuant to the most recent Performance Test.

If Seller fails to (i) establish the cure plan within the required ten (10) Day period set forth above in this Section 4 of **Appendix A** or, if applicable, establish the revised cure plan within the required fifteen (15) Day period set forth above in this Section 4 of **Appendix A** for a Cure Period extension, or (ii) diligently implement such cure plan (including implementation of such actions as Buyer may reasonably request), or (iii) cure the inadequate Tested Reliable Capacity within the applicable cure period, Seller shall pay Buyer, as liquidated damages, the buy down payment shown in Table A-1 corresponding to the Annual Period following the Annual Period in which the most recent Performance Test was conducted, based on the difference (in kW) between the then-effective lower limit of the Contracted Capacity range and the then-effective Tested Reliable Capacity. In addition, upon Seller making the required buy down payment hereunder, the lower limit of the then-effective Contracted Capacity range shall be reset at the Tested Reliable Capacity demonstrated in the most recent Performance Test and the upper limit of the then effective Contracted Capacity range will be lowered by the same amount that the lower limit has been reduced. However, for the avoidance of doubt, any such resetting of the lower and upper limits of the Contracted Capacity range shall not limit or modify Buyer's rights and remedies under Section 17.1.9 of this Agreement. Subject to Section 17.1.9 of this Agreement, the payment of buy down liquidated damages pursuant to this Section A.4 of **Appendix A** shall be Buyer's sole and exclusive remedy for a reduction of the Tested Reliable Capacity below the lower end of the Contracted Capacity range.

Table A-1[1]

Buy Down Payment for Capacity Reduction

Annual Period	Buy Down Payment ($/kW)
Annual Period 1	**REDACTED**
Annual Period 2	**REDACTED**
Annual Period 3	**REDACTED**
Annual Period 4	**REDACTED**
Annual Period 5	**REDACTED**

In the event the cure plan fails to restore the capacity to a value equal to or greater than the lower limit of the original Contracted Capacity range as set forth in Section A.1 of this **Appendix A** and the Contracted Capacity range is reset (lowered) as set forth above in this Section A.4 of **Appendix A**, and thereafter Seller is able to restore the capacity to a value equal to or greater than the lower limit of the original Contracted Capacity range as set forth in Section A.1 of this **Appendix A**, (i) Buyer will be required to refund to Seller any buy down liquidated damages paid by Seller hereunder (pro rated for the remaining period of the Term), and (ii) the restored capacity increment will be restored to Buyer at the Annual Capacity Price and pursuant to the capacity payment terms set forth herein. In such event, the Contracted Capacity range will be reset (raised) by an amount equal to the portion of the restored capacity increment.

5. **Capacity Pricing:** The "Annual Capacity Price" is as follows:

Table A-2
Annual Capacity Price

Calendar Year	($/kw-yr)
2024	**REDACTED**
2025	**REDACTED**
2026	**REDACTED**
2027	**REDACTED**
2028	**REDACTED**

[1] The buy down payment amounts in Table A-1 are expressed in 2023 US dollars. However, beginning on January 1, 2024 and continuing every January 1 of each year during the Term, the values shown in Table A-1 will be adjusted based on the change in CPI between the base year 2023 and each year during the Term, and such escalation shall be capped at a compound escalation rate of 4.75% per year.

The Annual Capacity Price shall include all fixed costs, including without limitation, fixed operation and maintenance charges.

B. **Monthly Capacity Payment:**

For each Month of each Annual Period, subject to the provisions of this Agreement, the "Monthly Capacity Payment" ("MCP") shall be determined as follows:

MCP = MCF – MAA

MCF = (DC * ACP * MVF) * 1,000

Where:

MCP = the Monthly Capacity Payment for such Month.

MCF = the Monthly Capacity Fee for such Month determined in accordance with this Section B of **Appendix A**.

MAA = the Monthly Availability Adjustment for such Month determined pursuant to Section C of **Appendix A**.

DC = Designated Capacity for such Month, as determined in accordance with Section A.3 of **Appendix A**.

ACP = the applicable Annual Capacity Price from Table A-2 of **Appendix A**.

MVF = the applicable Monthly Value Factor from Table A-3 of **Appendix A**.

In the event that the Delivery Commencement Date occurs on a Day other than the first Day of a Month, or if the last Day of the Term occurs on a Day other than the last Day of a Month, the calculation of the Monthly Capacity Payment and Monthly Availability Adjustment will be determined on a pro rata basis.

If the amount of the MCP for a Month is negative (i.e., the amount of the Monthly Availability Adjustment exceeds the amount of the Monthly Capacity Fee for such Month), then the Monthly Capacity Payment for the Month will be deemed to be zero dollars ($0.00) and Buyer will not be required to pay Seller a Monthly Capacity Payment for the Month.

Table A-3
Monthly Value Factor ("MVF")

Month	Monthly Value Factor
January	REDACTED
February	REDACTED
March	REDACTED
April	REDACTED
May	REDACTED
June	REDACTED
July	REDACTED
August	REDACTED

September	**REDACTED**
October	**REDACTED**
November	**REDACTED**
December	**REDACTED**

Notwithstanding the foregoing Monthly Value Factors in Table A-3, for any given Annual Period, Buyer shall be entitled, in its sole and absolute discretion, to modify the Monthly Value Factors for any or all Months by providing notice to Seller, provided that: (i) Buyer provides Seller such notice at least 180 Days prior to the commencement of such Annual Period; (ii) each Monthly Value Factor **REDACTED REDACTED REDACTED REDACTED REDACTED**; and (iii) the sum of all Monthly Value Factors for each Annual Period must equal 1.0.

C. **Monthly Availability Adjustment:**

For each Month of each Annual Period, Buyer shall determine the Monthly Availability Adjustment ("MAA") as follows:

MAA = (MCF * MAF)

Where:

MCF = the Monthly Capacity Fee for such Month determined in accordance with this Section B of **Appendix A.**

MAF = the Monthly Availability Factor for such Month from Table A-4 of **Appendix A** based on the MAP for such Month, as determined pursuant to this Section C of **Appendix A.**

MAP = the Monthly Availability Percentage for such Month as determined pursuant to this Section C of **Appendix A.**

1. **Calculation of Monthly Availability Percentage:**

The following formula is applicable to the calculation of the MAP for a Month:

$$MAP = 100\% - \frac{(FOH + EFDH - ARDH)}{DH}$$

Where:

FOH = The sum of Unplanned (Forced) Outage Hours for the Month in which the Facility would have been dispatched pursuant to Buyer's Schedules during the Month.

EFDH = The sum of Equivalent Unplanned (Forced) Derated Hours for the Month in which the Facility was or would have been dispatched pursuant to Buyer's Schedules during the Month. (For example, if a unit with a Designated Capacity of 500 MW was derated by 200 MW for 20 hours, EFDH = 20 * 200 / 500 = 8.)

ARDH = The sum of Alternate Resource Delivery Hours for the Month, which are the Unplanned (Forced) Outage Hours or Equivalent Unplanned (Forced) Derated Hours for the Month in which delivery is made from an Alternate Resource pursuant to Section 5.1.4.

DH = The sum of Dispatch Hours for the Month in which the Facility was or would have been dispatched pursuant to Buyer's Schedules during the Month; provided however, if such sum of the

Dispatch Hours for the Month is less than one hundred sixty eight (168), then DH shall be deemed to be equal to one hundred sixty eight (168).

The calculation of the MAP shall not include energy Scheduled during any period of: (i) Scheduled Outages or Maintenance Outages; (ii) Facility ramping; (iii) Force Majeure Events declared by Seller in accordance with Article 16 for which Seller has not elected Alternate Delivery pursuant to Section 5.1.4.3; and (iv) Unavailability Events to the extent they are directly caused by the acts or omissions of Buyer.

The Parties will develop an example calculation for MAP in the Operating Procedures.

2. **Monthly Availability Factor (Applicable to both AGC and Non-AGC Scheduling)**

The "Monthly Availability Factor" ("MAF") for each Month of each Annual Period shall be determined pursuant to Table A-4 and Table A-5, based on the MAP for such Month:

Table A-4

Monthly Availability Factor for January, February, May, June, July, August, September, and December

MAP	Monthly Availability Factor ("MAF")
Greater than or equal to 96%	0
Less than 96% but at least 60%	(96% – MAP)
Less than 60%	1.0

For a MAP greater than or equal to ninety-six percent (96%), the MAF will equal zero. There will be no increase in the Monthly Capacity Payment for a MAP of more than ninety-six percent (96%). For a MAP of at least sixty percent (60%) but less than ninety-six percent (96%), the MAF is equal to each percent or fraction thereof of MAP shortfall below ninety-six percent (96%). For example, in the event the MAP is ninety-five and two tenths percent (95.2%), there will be an eight tenths percent (0.8%) shortfall below ninety-six percent (96%), and the MAF will be eight tenths percent (0.8%). If the MAP is less than sixty percent (60%), the Monthly Capacity Fee is reduced to zero and the Monthly Capacity Payment will equal zero dollars ($0.00) for such Month.

Table A-5

Monthly Availability Factor for March, April, October, and November

MAP	Monthly Availability Factor ("MAF")
Greater than or equal to 93%	0
Less than 93% but at least 60%	(93% – MAP)
Less than 60%	1.0

For a MAP greater than or equal to ninety-three percent (93%), the MAF will equal zero. There will be no increase in the Monthly Capacity Payment for a MAP of more than ninety-three percent (93%). For a MAP of at least sixty percent (60%) but less than ninety-three percent (93%), the MAF is equal to each percent or fraction thereof of MAP shortfall below ninety-three percent (93%). For example, in the event the MAP is ninety-two and two tenths percent (92.2%), there will be an eight

tenths percent (0.8%) shortfall below ninety-three percent (93%), and the MAF will be eight tenths percent (0.8%). If the MAP is less than sixty percent (60%), the Monthly Capacity Fee is reduced to zero and the Monthly Capacity Payment will equal zero dollars ($0.00) for such Month.

APPENDIX B

ENERGY PAYMENT CALCULATION

A. Monthly Energy Payment Calculation

The Monthly Energy Payment ("MEP") shall be determined as follows:

$MEP = MEP_{FAC} + MEP_{AR}$

To the extent that energy is being provided from the Facility:

$MEP_{FAC} = MVOM_{GAS\text{-}FAC} + MSC_{GAS\text{-}FAC} + MFA_{GAS}$

To the extent energy is being provided from an Alternate Resource:

$MEP_{AR} = MVOM_{GAS\text{-}AR} + MSC_{GAS\text{-}AR} + MFC_{GAS\text{-}AR}$

Where:

MEP =	Monthly Energy Payment.
$MVOM_{GAS\text{-}FAC}$ =	Monthly Variable O&M Charge for energy provided from the Facility when dispatched on Natural Gas determined pursuant to Section B.
$MVOM_{GAS\text{-}AR}$ =	Monthly Variable O&M Charge for energy provided from Alternate Resources when the Facility would have been dispatched on Natural Gas determined pursuant to Section B.
$MSC_{GAS\text{-}AR}$ =	Monthly Startup Charge for energy provided from Alternate Resources when the Facility would have been dispatched on Natural Gas determined pursuant to Section C.
MFA_{GAS} =	Monthly Fuel Adjustment for operation on Natural Gas determined pursuant to Section D.1. The Monthly Fuel Adjustment for operation on Natural Gas does not apply when Seller is delivering energy from Alternate Resources.
$MFC_{GAS\text{-}AR}$=	Monthly Fuel Charge for Natural Gas for energy provided from Alternate Resources determined pursuant to Section D.
GHR_{GAS} =	The applicable Guaranteed Heat Rate in MMBtu/MWh when the Facility would have been dispatched on Natural Gas pursuant to **Appendix J**. The GHR for an hour will be based upon the MW Scheduled across the hour.
DFP_{GAS} =	Daily Fuel Price for Natural Gas in $/MMBtu.

In the event that Buyer disputes any Monthly Energy Payment as calculated by Seller, Buyer shall make a minimum Monthly Energy Payment for the applicable Month equal to the amount not disputed by Buyer. Such payment will remain subject to further adjustment in accordance with Section 6.2.

B. Monthly Variable O&M Charges ("MVOM")

The Monthly Variable O&M Charges shall be the sum of the hourly Variable O&M Charges for each delivered output level (from the Facility or Alternate Delivery) that is Scheduled during a given Month. The Variable O&M Charges for each delivered or Scheduled output level is the product of the delivered or Scheduled output level and the corresponding Variable O&M Rate. Variable O&M charges also apply to energy delivered from the Facility during ramping.

The Monthly Variable O&M Charges shall be determined as follows:

$$MVOM_{GAS\text{-}FAC} = \sum [(SE_{GAS\text{-}FAC} \cdot VOM_{GAS})_{Hour_1} \ldots (SE_{GAS\text{-}FAC} \cdot VOM_{GAS})_{Hour_N}]$$

$$MVOM_{GAS\text{-}AR} = \sum [(SE_{GAS\text{-}AR} \cdot VOM_{GAS})_{Hour_1} \ldots (SE_{GAS\text{-}AR} \cdot VOM_{GAS})_{Hour_N}]$$

Where:

$SE_{GAS\text{-}FAC}$ = Amount of Delivered Energy from the Facility each hour by Seller in MWh for operation on Natural Gas (pursuant to Buyer's Schedules) including energy produced during ramping of the Facility.

$SE_{GAS\text{-}AR}$ = Amount of Delivered Energy in MWh in each hour from Alternate Resources when the Facility would have been dispatched on Natural Gas in a given Month.

VOM_{GAS}= Variable O&M Energy Rate for operation on Natural Gas (which, for the avoidance of doubt, includes fired hour charges) is $\$_{REDACTED}$/MWh escalated at CPI. Other than escalation, VOM_{GAS} is a constant value and shall not vary based upon the Facility's hours of operation or MWh output.

C. Monthly Startup Charges ("MSC")

If Seller delivers energy from the Facility when dispatched on Natural Gas, the Monthly Startup Charge will be determined as follows:

$$MSC_{GAS\text{-}FAC} = \sum FSR_{GAS\text{-}1}]$$

If Seller delivers energy from Alternate Resources when the Facility would have been dispatched on Natural Gas, the Monthly Startup Charge will be determined as follows:

$$MSC_{GAS\text{-}AR} = \sum FSR_{GAS\text{-}1}$$

Where:

$\sum$= Summation from startup 1 to startup N.

$FSR_{GAS\text{-}1}$ = Fuel Startup Rate (in $/Startup Event) when dispatched on Natural Gas for moving from offline to one-on-one operation, as shown in Table B-2 below.

For purposes of determining Monthly Startup Charges, a Startup Event is defined as a change in the hourly delivered quantity according to Table B-2 below pursuant to Buyer's Scheduling Instructions.

A Startup Event is defined as follows:

- Offline to one-on-one startup is a charge created by a change in unit/Facility output from 0 MWh to the level designated as the minimum Energy output for one-on-one operation.

Energy produced by Seller and delivered to Buyer from startup to Minimum Capacity and from Minimum Capacity to offline will be paid for at the Guaranteed Heat Rate at Minimum Capacity.

Table B-2
Startup Rate ($/Startup Event) for Operation on Natural Gas

		Offline to One-on-One Operation
Fuel Startup Rate ($/event)		**$REDACTED*** [2]

* Provided that the delivered amount meets or exceeds the minimum 1 on 1 Designated Capacity.

D. Monthly Fuel Adjustment.

If Seller delivers energy from the Facility in accordance with Buyer's Schedule or in response to an AGC signal provided by Buyer, Buyer shall determine the Daily Guaranteed Fuel quantity by multiplying the Guaranteed Heat Rate of the Scheduled amount or the AGC instructed output, as the case may be, pursuant to **Appendix J** and Section 13 by the amount of energy that was delivered to Buyer. The Operating Representatives will develop procedures for determining energy produced and delivered pursuant to Buyer's Schedule during ramping of the Facility, including (i) from synchronization to Minimum Capacity (Startup Energy), and (ii) from Minimum Capacity to the maximum Energy output of the Facility. Such ramping energy shall be multiplied by the appropriate Guaranteed Heat Rates pursuant to **Appendix J** to determine the Daily Guaranteed Fuel quantity during ramping.

If the actual heat rate is different than the applicable Guaranteed Heat Rates, then a Monthly Fuel Adjustment shall be made to Buyer's next invoice.

D.1. Monthly Fuel Adjustment ("MFA_{GAS}") for operation on Natural Gas

The Monthly Fuel Adjustment ("MFA_{GAS}") for operation on Natural Gas shall be determined as follows:

$$MFA_{GAS} = \sum\{[(DGF_{GAS} - DAF_{GAS}) \cdot DFC_{GAS}]_{DAY\,1} \ldots [(DGF_{GAS} - DAF_{GAS}) \cdot DFC_{GAS}]_{DAY\,N}\}$$

The Monthly Fuel Adjustment ("MFA_{GAS}") shall be the sum of the daily fuel adjustments for each Gas Day or partial Gas Day in the Month. The daily fuel adjustment is the product of the difference of Daily Guaranteed Fuel and Daily Actual Fuel in MMBtu and the corresponding Daily Fuel Cost in $/MMBtu. Notwithstanding the above, in any Gas Day in which the Daily Actual Fuel is within +/- 1.5% of the Daily Guaranteed Fuel, then, for purposes of calculating the daily fuel adjustment for

[2] The Fuel Startup Rate in Table B-2 is expressed in 2023 US dollars. However, beginning on January 1, 2024 and continuing every January 1 of each year during the Term, the value shown in Table B-2 will be adjusted based on the change in CPI between the base year 2023 and each year during the Term, and such escalation shall be capped at a compound escalation rate of 4.75% per year.

such Gas Day, the Daily Actual Fuel shall be deemed to be equal to the Daily Guaranteed Fuel.

Where:

DGF_{GAS} = The Daily Guaranteed Fuel quantity in MMBtu for operation on Natural Gas.

DAF_{GAS} = The Daily Actual Fuel quantity allocated to Buyer's consumption (to generate energy pursuant to Buyer's Schedules) in MMBtu for operation on Natural Gas as measured at the Primary Gas Delivery Point.

DFC_{GAS} = The Daily Fuel Cost in $/MMBtu for operation on Natural Gas.

The Daily Guaranteed Fuel quantity for operation on Natural Gas shall be the sum of the hourly MMBtus that would have been burned using the appropriate Guaranteed Heat Rate multiplied by the corresponding hourly Delivered Energy, excluding energy produced during Startup ramping, by Seller pursuant to Buyer's Schedule.

$$DGF_{GAS} = \sum [(GHR_{GAS\ hr\ 1} * SE_{GAS\text{-}FAC}) \ldots (GHR_{GAS\ hr\ N} * SE_{GAS\text{-}FAC\ hr\ N})]$$

In any period in which the Facility is in a Startup operation, (i.e., the period from synchronization to Minimum Capacity), the contribution to the Daily Guaranteed Fuel quantity shall be deemed to be 2,600 MMBtu/Startup (Hot Start) and 3,200 MMBtu/Startup (Cold Start), respectively.

The Daily Actual Fuel quantity for operation on Natural Gas shall be the sum of the hourly MMBtus allocated to Seller each Day corresponding to the actual amount of Natural Gas consumed in the Facility to meet Buyer's Schedules on each Day and any greater or lesser adjustment to account for differences between the total gas measured at the Primary Gas Delivery Point and the actual total consumption at the Facility.

The Daily Fuel Cost (DFC_{GAS}) for operation on Natural Gas shall be determined as follows:

DFC_{GAS} = (TGD + VTA + IT)

Where:

TGD = The Gas Day's "Gas Daily" midpoint price for its Daily Price Survey for Florida Gas Zone 3 index under the heading Louisiana/Southeast. If the index fails to publish or is no longer representative of supply costs to the Facility, the Parties may agree to replace the reference price with any index that is representative of the cost to purchase physical gas supply for the Facility.

VTA = The Variable Transportation Adders will be Gulf South's maximum firm transportation variable charges including all fuel retention and surcharges.

IT = The Interruptible Transportation rate will be Gulf South System's maximum Interruptible Transportation Charges for any amount needed above the Firm Transportation capacity or additional firm transportation procured by Buyer.

If the Monthly Fuel Adjustment for operation on Natural Gas is positive, the Buyer shall pay Seller the amount of the Monthly Fuel Adjustment for operation on Natural Gas. If the Monthly Fuel Adjustment for operation on Natural Gas is negative, the Seller shall pay Buyer the absolute value amount of the Monthly Fuel Adjustment for operation on Natural Gas.

E. Monthly Fuel Charge.

If Seller delivers energy from Alternate Resources, the Monthly Fuel Charge will be determined as follows:

$$MFC_{GAS\text{-}AR} = \sum[(DGF_{GAS\text{-}AR} \cdot DFP_{GAS\text{-}AR})_{DAY\ 1} \ldots (DGF_{GAS\text{-}AR} \cdot DFP_{GAS\text{-}AR})_{DAY\ N}]$$

The Monthly Fuel Charge shall be the sum of the daily fuel charges for each Day or partial Gas Day in the Month when delivering from an Alternate Resource. The daily fuel charge is the product of the Daily Guaranteed Fuel in MMBtus and the corresponding Daily Fuel Price in $/MMBtu.

Where:

$DGF_{GAS\text{-}AR}$ = Daily Guaranteed Fuel quantity in MMBtus for energy delivered from Alternate Resources.

The Daily Guaranteed Fuel ("DGF") shall be the sum of the hourly MMBtus that would have been burned at the appropriate Guaranteed Heat Rate pursuant to **Appendix J** multiplied by the corresponding hourly Delivered Energy pursuant to Buyer's Schedule, excluding ramping.

If Seller is delivering from an Alternate Resource, the following equation would apply:

$$DGF_{GAS\text{-}AR} = \sum [(GHR_{GAS\ hr\ 1} * SE_{GAS\text{-}AR\ hr\ 1}) \ldots (GHR_{GAS\ hr\ N} * SE_{GAS\text{-}AR\ hr\ N})]$$

The Daily Fuel Price ($/MMBtu) shall be determined for a given Day in a Month as follows:

$DFP_{GAS\text{-}AR}$ = The Gas Day's "Gas Daily" midpoint price for its Daily Price Survey for Florida Gas Zone 3 index under the heading Louisiana/Southeast. If the index fails to publish or is no longer representative of supply costs to the Facility, the parties may agree to replace the reference price with any index that is representative of the cost to purchase physical gas supply for the Facility.

APPENDIX C

TECHNICAL LIMITS AND SCHEDULE PROCEDURES

I. TECHNICAL LIMITS

A. General Requirements

Subject to the Technical Limits set forth in subsections B, C, D, E and F of this Section I of **Appendix C**, the Facility shall be capable of meeting Buyer's Schedules at all times during the Term following the Delivery Commencement Date, twenty-four (24) hours per Day, seven (7) Days per week. Seller may propose modifications or changes to the Technical Limits based on specifications and recommendations, as modified from time to time, of the equipment manufacturers of the CT and CT generator, steam turbine and steam turbine generator and HRSG provided that (1) any such modifications or changes that in Buyer's sole judgment may adversely affect Buyer's Scheduling flexibility (including without limitation, magnitude, duration and response time) under this Agreement shall be subject to the prior written approval of Buyer's Operating Representative, and (2) in the event such changes limit Buyer's Scheduling flexibility more than the limits as set forth below, Seller shall make commercially reasonable efforts to minimize the effect of any such equipment manufacturer's specifications or recommendations on Seller's ability to deliver energy in response to Buyer's Schedules. The Parties shall develop procedures for the testing contemplated in **Appendix C**; provided, however, that reasonable demonstration of such capabilities from prior testing or operation may be used instead.

B. Minimum Capacity Limits / Net Output

Minimum output level shall be established at the level that the Facility is able to remain operationally stable and remain in compliance with permitted emissions limits ("Minimum Capacity"). The Facility is estimated to have a minimum output level of approximately **REDACTED** MW.

C. Maximum Ramp Rates

Maximum ramp rates are as specified in the following table:

Max Ramp Rate	Base * MW/minute	
One (1) CT/G On-line	10	
* Maximum ramp rates based on a hot steam turbine condition; cold starts require steam turbine soak at various points during start-up sequence.		

D. Minimum Schedule and Minimum Down Times

The minimum Schedule time is eight (8) consecutive hours; provided, however, Buyer shall have the right, not to exceed thirty (30) times per Annual Period, to terminate a Schedule after four (4) consecutive hours if the original Schedule was based upon a contemplated eight (8) consecutive hours or more of continuous operation. Start-up and ramping will be accomplished prior to the Scheduled hours. The minimum down time shall be three (3) hours; provided, however, Buyer shall have the right not to exceed twelve (12) times per Annual Period to call for a restart after less than three (3) hours, only limited by the ramping capability of the Facility. Additionally, Buyer shall utilize the three (3) hour minimum down time constraint in the normal day-ahead unit commitment process.

E. Starts

The maximum number of turbine starts is one (1) start per turbine per calendar Day.

F. Required Startup Notification

Plant start times are as specified in the following table:

Start Classification (Off-line Hours)	Start Time to Minimum (1) (hours)	Start Time to Full Load (1) (hours)
Hot (< 8 hours)	2.0	2.5
Warm (8 < hours < 48)	3.0	3.5
Cold (> 48 hours)	4.0	4.5
Winter Cold (2) (> 48 hours)	4.0	4.5
Notes: 1. Start Time equals time of notice. (Seller shall provide Buyer with copies of results of any tests that demonstrate the ability of the Facility to meet the above start times.) 2. Winter cold applies when freeze mitigation actions have been taken by operator, provided that Seller shall promptly notify Buyer prior to implementing any planned freeze mitigation actions and afford Buyer a reasonable opportunity to Schedule the Facility in lieu of implementing such freeze mitigation actions.		

G. Natural Gas Pipeline Pressure

Natural Gas deliveries under this Agreement shall be at a pressure that is greater than or equal to the lower of (i) 450 psig, or (ii) the minimum pressure recommended by the manufacturer to operate a unit on Natural Gas, as such modification may be modified from time to time.

II. SCHEDULE PROCEDURES

This Section II of **Appendix C** sets forth the procedures to be followed by Buyer and Seller for notification and Scheduling the Facility when it is called for by Buyer. The procedures specified are subject to change upon mutual agreement of the Parties.

A. Notification Communication

1. Three Months prior to the Delivery Commencement Date, Seller shall supply the Scheduling Center with the names of the personnel who can be called to Schedule energy. Seller will provide Buyer a single phone number that will be answered twenty-four (24) hours a Day and corresponding fax number and email address. Seller shall keep this information current.

2. Three Months prior to the Delivery Commencement Date, the Scheduling Center shall supply Seller with the names of individuals to be contacted concerning availability of the Facility and energy Schedules. The Scheduling Center will provide Seller with a single phone number that will be answered twenty-four (24) hours per Day and corresponding fax number and email address. The Scheduling Center shall keep this information current.

B. Scheduling and Notification Procedures

1. By 12:00 p.m. (noon) CPT of each Business Day, or by 8:30 a.m. CPT if Seller has elected to deliver from an Alternate Resource, the Scheduling Center will contact Seller if it anticipates submitting a Schedule for the next Business Day and any subsequent Days which are not Business Days (the period covered by such Schedule being referred to as a "Scheduling Period"). The Scheduling Center will provide a Schedule for each hour of the Scheduling Period in accordance with Article 13. The Scheduling Center shall also provide a good faith, non-binding estimate for the next Scheduling Period. The Scheduling Center is not obligated to contact Seller if it does not plan to submit a Schedule for a Scheduling Period.

2. On or before 1:30 p.m. CPT, Seller shall inform the Scheduling Center if the Facility or in the case of Alternate Delivery, the Alternate Resource, will be de-rated during the next Scheduling Period. Seller shall provide an estimate of the time and degree to which the generation levels will be reduced. Unless due to the declaration of a Force Majeure Event, such Seller notification does not preclude Buyer from requesting any amount of energy from the Facility or relieve Seller of its obligation to deliver energy in accordance with any Scheduling Instructions.

3. Seller shall promptly inform the Scheduling Center of any equipment problems or unplanned outages and the expected time and degree to which generation levels will be reduced. During Facility Outages, Seller shall continue to keep Buyer informed as to the expected date when the Facility, or in the case of Alternate Delivery, the Alternate Resource, will be returned to service for dispatch.

4. Intra-Day Scheduling shall be permitted in accordance with the provisions of Article 13.

Procedures will be established as needed for the Scheduling of energy delivered from an Alternate Resource; provided, however, that Seller bears the ultimate responsibility for all tagging and other transmission arrangements with respect to such deliveries.

APPENDIX D

PERFORMANCE TESTING PROCEDURES

1. Objective

The purpose of this **Appendix D** is to provide an agreed upon method for the determination of Tested Reliable Capacity beyond the initial Tested Reliable Capacity. Consistent, past performance of the Facility in reliably meeting the Designated Capacity and in reliably meeting the Scheduling Instructions shall be deemed as acceptable demonstration of the capability of the Facility.

During the Performance Test for purposes of determining the Tested Reliable Capacity, the Facility's actual net plant output will be corrected to Reference Conditions at the Site.

2. Operating Conditions

During the Performance Test, the Facility will be operated within the normal design limits, consistent with continuous operation, and in accordance with Prudent Industry Practices, as confirmed by available unit operating data. The gas turbines will be operated at maximum load for the duration of the test. All auxiliary systems will be operated as appropriate for the actual ambient conditions existing during the test period.

3. Testing

On the date of the Performance Test, the Facility shall be brought to maximum load using Natural Gas. The test shall be scheduled between the weekday hours of 7:00 a.m. and 7:00 p.m. local time and as close as practical with Buyer's Scheduling requirements. During the test period separate tests will be conducted at base load for determination of Tested Minimum and Maximum Capacity. Data will be collected for a minimum of two (2) hours at maximum capability. To the extent that the Facility experiences equipment malfunction, unsteady operation or unreliability during any test or its historical operating records show difficulty or unreliability during testing of the Facility or deficiencies in meeting Buyer's Schedules, Buyer may request that Seller perform additional testing of the Facility at Seller's expense in order to demonstrate to Buyer's reasonable satisfaction the reliability of the Facility.

Testing will be performed in general accordance with ASME PTC 46 (Performance Test Code on Overall Plant Performance) and other applicable industry standards and all Legal Requirements. All Performance Test activities will be conducted by, or under the supervision of, Seller and its contractors. Buyer shall have the right to have a representative present to witness Performance Tests conducted pursuant to this Agreement. Each Party will notify the other of its intent to conduct any test with a six (6) Business Day advanced written notice as specified in **Appendix A**.

Actual net output of the Facility will be metered with the Metering System. No commercial test tolerances or measurement uncertainties will be applied to test results.

4. Reduction of Data

Actual tested capacity will be adjusted to the Reference Conditions, using correction curves provided by Seller or its engineer in accordance with the following equation:

Tested Reliable Capacity = Actual Maximum Net Output x Fwetblb1 x Fbaro1 x Fpf1 x DP/100

Where:

Actual Maximum Net Output = actual net Facility output measured during the test conducted at maximum base load.

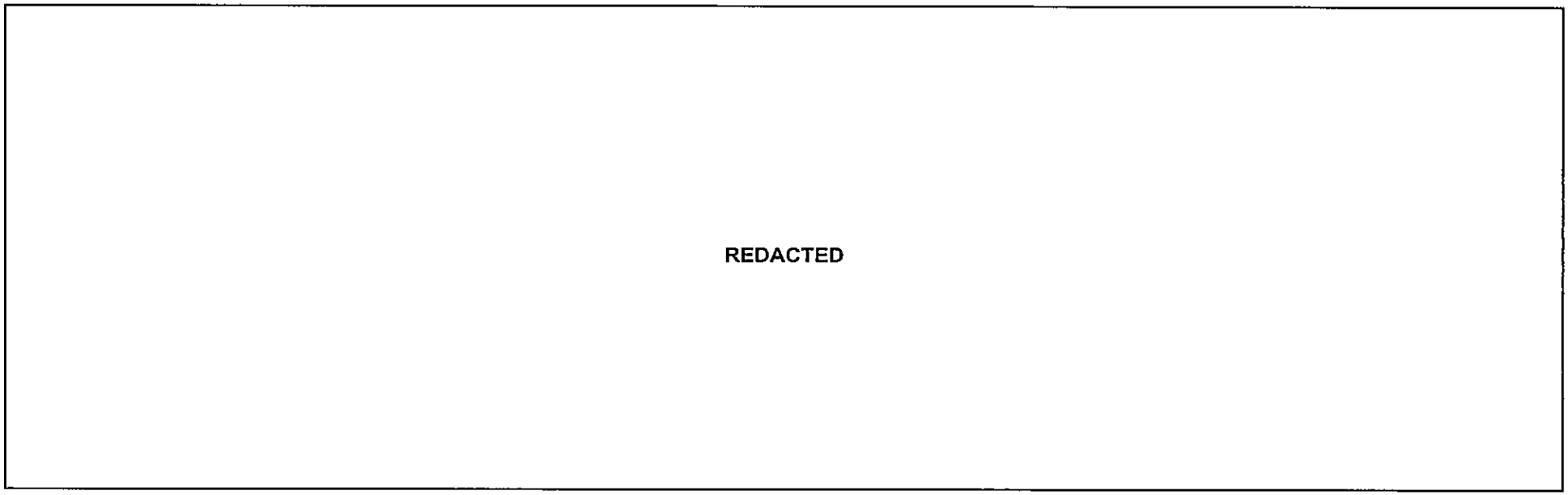
Fwetblb = correction factor for dry bulb temperature and relative humidity from actual conditions to Reference Conditions. Fwetblb for the Facility = Figure D1.

Fbaro = correction for barometric pressure from actual test conditions to Reference Conditions. Fbaro for the Facility = Figure D2.

Fpf = correction for reactive power output from actual test conditions to Reference Conditions. Fpf for the Facility = Figure D3.

DP = the dedicated percentage of the Facility that is committed to this Agreement, which for the Facility = 100%.

Figure D-1: Power Output vs. Dry Bulb temperature and Relative Humidity



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REDACTED

Figure D-2: Power Output vs. Barometric Pressure

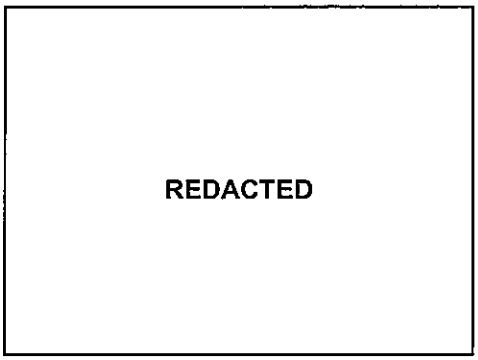
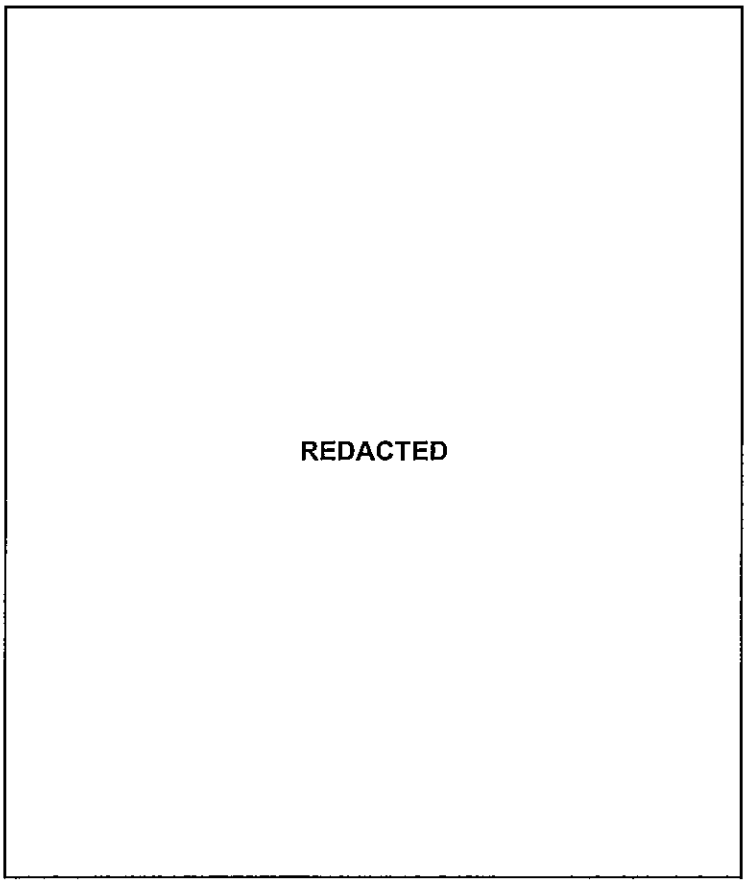


Figure D-3: Power Output vs. Generator Reactive Power Output



APPENDIX E

RESERVED

APPENDIX F

RESERVED

APPENDIX G

THE SITE

The Site shall be defined as:

The land, rights-of-way and related equipment and facilities of the Santa Rosa Energy Center electric generating plant located in Santa Rosa County, Florida at 5001 Sterling Way, Pace, Florida, 32571.

APPENDIX H

FORM OF STANDBY LETTER OF CREDIT

[Bank Letterhead]

Date of issuance: _____, 20__

Irrevocable Standby Letter of Credit No.:_____

"Issuer": _____

Address: _____

"Beneficiary": _____

Address: _____

"Account Party": _____

Address: _____

"Expiry Date": _____, 20__, and any automatically extended date, as herein provided [(but in no event later than _____, 20__)]

"Total Amount": _____United States Dollars (U.S. $_____)

We, the Issuer, hereby establish in your favor, for the account of the Account Party, our irrevocable standby letter of credit (this "**Standby Letter of Credit**"), in the aggregate amount not exceeding the Total Amount.

Funds under this Standby Letter of Credit are available to you on or before the Expiry Date against your sight draft drawn on us in the form attached as Annex 1 hereto, with appropriate insertions, and referring thereon to the number of this Standby Letter of Credit, accompanied by a completed certificate signed by a person purporting to be one of your officers or authorized representatives, in the form attached as Annex 2 hereto, with appropriate insertions.

This Standby Letter of Credit is effective immediately and expires at 5:00 p.m. (Eastern Prevailing time) on the Expiry Date, as the same may be extended. It is a condition of this Standby Letter of Credit that the Expiry Date will be deemed automatically extended without amendment for a period of one year from the present or any future Expiry Date, unless we notify you not less than ninety (90) days prior to any such date, in accordance with the notice provisions set forth herein, that we have elected not to extend the Expiry Date for such additional period.

Presentation of such drafts and such certificates will be made on any day that is a business day for us at or prior to 5:00 p.m. (Eastern Prevailing Time) at our office located at _____, Atlanta, Georgia, or at any other office in Atlanta, Georgia or New York, New York, that is designated by us in a written notice delivered to you. If such sight draft and such certificate are received at any such office on or prior to the Expiry Date, we hereby agree with you that we will duly honor the same within two (2) business days of such presentation.

Drawings may also be presented to us by facsimile transmission to facsimile number [_____]. Beneficiary may contact the Issuer at [_____] to confirm receipt of the transmission. Beneficiary's failure to seek such a telephone confirmation does not affect the Issuer's obligation to honor such a presentation. If you present a facsimile drawing under this Letter of Credit, you do not need to present the original of any drawing documents and the facsimile transmission will constitute the operative drawing documents.

Partial drawings and multiple presentations may be made under this Standby Letter of Credit, provided, however, that each such demand that is paid by us will reduce the amount available under this Standby Letter of Credit.

Except as is expressly set forth herein, payment of drafts drawn under this Standby Letter of Credit is not subject to any condition or qualification. The obligation of the Issuer under this Standby Letter of Credit is the independent obligation of the Issuer and is in no manner contingent upon reimbursement with respect thereto.

This Standby Letter of Credit is transferable and can be successively transferred to any transferee that Beneficiary states in writing to us has succeeded such Beneficiary under this Letter of Credit; provided that such transfer to such transferee is in compliance with applicable U.S. laws and regulations. Transfer of this Standby Letter of Credit to any transferee will be effected by the presentation to us of this Standby Letter of Credit accompanied by a certificate in the form attached as Annex 3 hereto, with appropriate insertions, signed by a person purporting to be an officer or authorized representative of the Beneficiary. Upon such presentation we will forthwith issue an irrevocable letter of credit to such transferee with provisions therein consistent with this Standby Letter of Credit.

This Standby Letter of Credit sets forth in full the terms of our undertaking, and such undertaking may not be modified, annulled or amplified by reference to any other document, instrument or agreement referred to herein or in which this Standby Letter of Credit is referred or to which this Standby Letter of Credit relates, and any such reference may not be deemed to incorporate herein by reference any such document, instrument or agreement.

To the extent not contrary to the express terms hereof, this Standby Letter of Credit will be governed by the International Standby Practices (herein referred to as the "**ISP98**"). As to matters not governed by the ISP98, this Standby Letter of Credit will be governed by and construed in accordance with the laws of the state of Georgia.

Notices concerning this Standby Letter of Credit may be sent to a party by hand delivery or by certified mail or registered mail, or by electronic transmission to its respective address set forth herein. Any notice, demand, request or other communication will be deemed to have been received by the party to whom it is sent at the time of its delivery. Each party may notify the other of any change of address in the manner provided above.

[ISSUING BANK]

By:_____
Authorized Signature

ANNEX 1

FORM OF SIGHT DRAFT

[Insert Place], [Insert Date]

Amount: [Insert Currency][Insert Amount in Numbers]
[Insert Amount in Letters]

Drawn under Irrevocable Standby Letter of Credit No. _____ of [Insert Name of Issuing Bank]

At Sight

Pay to the Order of [Name of Beneficiary]

In reference to: Irrevocable Standby Letter of Credit No. _____, dated _____.

To: [Insert Name of Issuing Bank]
[Insert Address]

[BENEFICIARY]

By:_____

Title:_____

ANNEX 2

FORM OF CERTIFICATE

Re: [Insert Name of Agreement] dated _____, 20__ (the "**Agreement**") between [Name of Account Party] ("**[Account Party]**") and [Name of Beneficiary] ("[**Beneficiary**]").

The undersigned, an officer or authorized representative of [Beneficiary], hereby certifies to [ISSUING BANK] (the "**Bank**") with reference to irrevocable standby letter of credit no. (the "**Standby Letter of Credit**"), issued by the Bank for the account of [Account Party] in favor of [Beneficiary] that:

(1) (Insert one of the following, as applicable)

Pursuant to the Agreement, Beneficiary is entitled to demand payment under the Standby Letter of Credit in the amount of the sight draft accompanying this certificate.

or

[Beneficiary] has received written notice from the Bank in accordance with the terms of the Standby Letter of Credit that the Bank has elected not to extend the Expiry Date of the Standby Letter of Credit for an additional period past its then Expiry Date and the Account Party has failed to deliver a substitute letter of credit in accordance with the terms of the Agreement.

(2) The undersigned is an officer or authorized representative of [Beneficiary] and is authorized to execute and deliver this certificate and to draw upon the Standby Letter of Credit.

IN WITNESS WHEREOF, the undersigned has executed and delivered this Certificate as of this __ day of _____ , 20__.

[BENEFICIARY]

By:_____

Title:_____

ANNEX 3

INSTRUCTION TO ASSIGN IN ENTIRETY

_____, 20__

Re: Irrevocable Standby Letter of Credit No.

Gentlemen:

For value received, the undersigned beneficiary hereby irrevocably assigns to:

(Name of Assignee)
(Address)

all rights of the undersigned beneficiary to demand payment under the above Standby Letter of Credit in its entirety.

By this assignment, all rights of the undersigned beneficiary in such Standby Letter of Credit are transferred to the assignee and the assignee will hereafter have the sole rights as beneficiary thereof.

The Standby Letter of Credit is returned herewith and in accordance therewith we ask you to issue a new irrevocable Standby Letter of Credit in favor of the assignee with provisions consistent with the Standby Letter of Credit.

Very truly yours

[Beneficiary]

By:_____

Title:_____

APPENDIX I

FORM OF GUARANTY

THIS GUARANTY AGREEMENT (the "**Guaranty**"), dated and effective as of _____, 20__, is made and entered into by _____ (the "**Guarantor**") in favor of the _____ (the "**Beneficiary**").

WHEREAS Beneficiary and _____ (the "**Company**"), [a subsidiary of the Guarantor], have entered into that certain [Insert Name of Agreement] dated as of _____, 20__ (as amended, restated, supplemented or otherwise modified from time to time, the "**Agreement**");

WHEREAS, the Beneficiary has required, as an inducement to its entry into the Agreement, that Guarantor deliver to the Beneficiary this Guaranty or other Eligible Collateral as and when required under the Agreement;

WHEREAS, the Guarantor qualifies as a Seller Guarantor under the Agreement and this Guaranty qualifies as Eligible Collateral under the Agreement; and

WHEREAS, the Guarantor will derive substantial direct and indirect benefit from the transactions contemplated by the Agreement.

NOW, THEREFORE, to induce the Beneficiary to enter into the Agreement and perform its obligations thereunder, and for and in consideration of the foregoing premises, the mutual agreements contained herein and other good and valuable consideration, the receipt and sufficiency of which are hereby acknowledged, the Guarantor agrees as follows:

DEFINITIONS

Definitions. Unless otherwise defined in this Guaranty, capitalized terms have the meanings specified or referred to in the Agreement.

GUARANTY

Guaranty. Guarantor hereby unconditionally and irrevocably guarantees to the Beneficiary and its successors and assigns, the prompt and full payment of any and all obligations of the Company to the Beneficiary when due, whether by acceleration or otherwise, with such interest as may accrue thereon, under the Agreement or under any other documents or instruments now or hereafter evidencing, securing or otherwise relating to the Agreement (the "**Guaranteed Obligations**"); provided, however, that Guarantor's liability under this Guaranty will in no event exceed the aggregate amount of Eligible Collateral required to be provided by Seller from time to time pursuant to Article 5 of the Agreement (plus costs of enforcement of this Guaranty as provided in Section 4.4 below), as the case may be. Guarantor will immediately pay any obligation of Company upon demand by the Beneficiary.

Guaranty Absolute. 4.1.1.1.1.1 The Guarantor absolutely guarantees that the Guaranteed Obligations will be paid strictly in accordance with the terms of the Agreement, regardless of any law or regulation now or hereafter in effect in any jurisdiction affecting any of such terms or the rights of the Beneficiary with respect thereto. This Guaranty constitutes a guarantee of payment and not of collection. The obligations of the Guarantor hereunder are several from the Company or any other person, and are primary obligations concerning which the Guarantor is the principal obligor. The liability of Guarantor under this Guaranty will be direct and immediate and not conditional or contingent upon the pursuit of any remedies against the Company or any other person, nor against securities or liens available to the Beneficiary, its successors or assigns. The liability of the Guarantor under this Guaranty will be irrevocable, absolute and unconditional irrespective of, and the Guarantor hereby irrevocably waives any defenses it may now have or hereafter acquire in any way relating to, any or all of:

any change in the time, manner or place of payment of, or in any other term of, all or any of the Guaranteed Obligations, or any other amendment, modification or waiver of, or any consent to departure from, the terms of such Guaranteed Obligations, or any compromise, settlement, release or termination of any of the Guaranteed Obligations;

any change, restructuring or termination of the corporate structure or existence of the Company or any of its subsidiaries, including, without limitation, any disposal by the Guarantor of all or any part of its interest in the Company, or otherwise alter its investment in the Company in any manner;

any lack of validity or enforceability, in whole or in part, of the Guaranteed Obligations, the Agreement or any agreement or instrument relating thereto;

any failure of the Beneficiary to disclose to either the Company or the Guarantor any information relating to the business, condition (financial or otherwise), operations, performance, properties or prospects of either the Company or any of its subsidiaries now or hereafter known to the Beneficiary (the Guarantor waiving any duty on the part of the Beneficiary to disclose such information);

any failure, omission, delay or lack on the part of Beneficiary to enforce, ascertain or exercise any right, power or remedy under or pursuant to the terms of the Agreement, the Guaranteed Obligations or this Guaranty;

any failure of the Beneficiary to commence an action against Company, including without limitation as contemplated by the provisions of O.C.G.A. Section 10-7-24, as amended;

any lack of due diligence by the Beneficiary in the collection or protection of or realization upon any collateral securing the Guaranteed Obligations;

the bankruptcy, insolvency, winding up, dissolution, liquidation, administration, reorganization or other similar or dissimilar failure or financial disability of the Guarantor or the Company or any legal limitation, disability, incapacity, or other circumstance relating to the Guarantor or the Company;

the addition, substitution or partial or entire release of any guarantor, maker or other party (including the Company) primarily or secondarily liable or responsible for the payment and observance of the Guaranteed Obligations or by any extension, waiver, amendment or thing that may release or discharge (in whole or in part) a guarantor, maker or third party (other than as a result of the indefeasible payment of the Guaranteed Obligations in full);

the taking, variation, renewal, addition, substitution, subordination, or partial or entire release of any security or other credit support for the Guaranteed Obligations, or the enforcement or neglect to perfect or enforce any such security or support; or

except as provided in Section 2.3(c), any other circumstance whatsoever (including, without limitation, any statute of limitations) or any act of the Beneficiary or any existence of or reliance on any representation by the Beneficiary that might otherwise constitute a legal or equitable defense available to, or a discharge of, the Guarantor.

This Guaranty will continue to be effective or be reinstated, as the case may be, if at any time any payment of any of the Guaranteed Obligations should for any reason subsequently be asserted, or declared, to be void or voidable or is unwound in any way under any state or federal law, including without limitation any provision of the Bankruptcy Code related to fraudulent conveyance or preference (each a "**Voidable Transfer**"), and Beneficiary or any other person is not required to repay or restore, in whole or in part, any such Voidable Transfer, or Beneficiary or any other person elects to do so, all as though such payment had not been made.

No action that the Beneficiary takes or fails to take in connection with the Guaranteed Obligations, or any security for the payment of any of the Guaranteed Obligations, nor any course of dealing with Company or any other person, will release Guarantor's obligations hereunder, affect this Guaranty in any way, or afford Guarantor any recourse against the Beneficiary.

In the case of an Event of Default under the Agreement or with regard to any of the Guaranteed Obligations, Guarantor hereby consents and agrees that the Beneficiary will have the right to enforce its rights, powers, and remedies thereunder or hereunder or under any other instrument now or hereafter evidencing, securing, or otherwise relating to the Guaranteed Obligations, and apply any payments or credits received by the Company or Guarantor or realized from any security, in any manner and in any order as the Beneficiary, in its sole discretion, sees fit, and all rights, powers, and remedies available to the Beneficiary in such event will be nonexclusive and cumulative of all other rights, powers, and remedies provided thereunder or hereunder or by law or in equity. If the Guaranteed Obligations are partially paid by reason of the election of the Beneficiary, its successors or assigns, to pursue any of the remedies available to the Beneficiary, or if such indebtedness is otherwise partially paid, this Guaranty will nevertheless remain in full force and effect, and Guarantor will remain liable for the entire balance of the Guaranteed Obligations even though any rights that Guarantor may have against the Company may be destroyed or diminished by the exercise of any such remedy.

Waivers and Acknowledgments.

(a) Guarantor hereby waives promptness, diligence, presentment, demand of payment, acceptance, notice of acceptance, protest, notice of dishonor and any other notices with respect to any of the Guaranteed Obligations and this Guaranty.

(b) The Guarantor hereby unconditionally and irrevocably waives any right to revoke this Guaranty and acknowledges that this Guaranty is continuing in nature and applies to all Guaranteed Obligations, whether existing now or in the future. The provisions of this Guaranty will extend and be applicable to all renewals, amendments, extensions, consolidations, and modifications of the Agreement.

The Guarantor hereby waives and relinquishes all rights and remedies accorded by application of law to sureties or guarantors and agrees not to assert or take advantage of any such rights or remedies, including without limitation:

Any right to require the Beneficiary to proceed against the Company or any other person or to proceed against or exhaust any security held by the Beneficiary at any time or to pursue any other remedy in the Beneficiary's power before proceeding against the Guarantor;

Any defense that may arise by reason of the incapacity, lack of authority, death or disability of any other person or the failure of the Beneficiary to file or enforce a claim against the estate (in administration, bankruptcy or any other proceeding) of any other person; or

Any defense arising because of the exercise of any right or remedy available to, or election made by, the Beneficiary pursuant to the Federal Bankruptcy Code, whether as an unsecured or undersecured creditor, seeking adequate protection or otherwise.

The Guarantor hereby unconditionally and irrevocably waives any defense based on any right of set-off or counterclaim against or in respect of the obligations of the Guarantor hereunder.

The Guarantor waives any and all defenses, claims and discharges of Company, or any other obligor pertaining to the Guaranteed Obligations. Without limiting the generality of the foregoing, the Guarantor will not assert, plead or enforce against the Beneficiary or any other person any defense of waiver, release, statute of limitations, res judicata, statute of frauds, fraud, incapacity, minority, usury, illegality or unenforceability which may be available to the Company or any other person liable in respect of any

indebtedness, or any setoff available against the Beneficiary to the Company or any such other person, whether or not on account of a related transaction. The Guarantor expressly agrees to waive reliance on any anti-deficiency statute(s). If a foreclosure proceeding is commenced, the Guarantor expressly agrees that he will be and remain unconditionally liable, to the fullest extent permitted by applicable law, for any deficiency remaining after foreclosure of any mortgage or security interest securing indebtedness, whether or not the liability of the Company or any other person for such deficiency is discharged pursuant to statute or judicial decision.

Subrogation. Notwithstanding any payment or payments made by the Guarantor hereunder, the Guarantor hereby irrevocably waives any and all rights of subrogation to the rights of the Beneficiary against the Company and any and all rights of reimbursement, assignment, indemnification or implied contract or any similar rights (including without limitation any statutory rights of subrogation under Section 509 of the Bankruptcy Code, 11 U.S.C. § 509) against the Company or against any other guarantor of all or any part of the Guaranteed Obligations until such time as the Guaranteed Obligations have been indefeasibly paid or performed in full. If, notwithstanding the foregoing, any amount will be paid to the Guarantor on account of such subrogation or similar rights at any time when all of the Guaranteed Obligations will not have been indefeasibly paid in full, such amount will be held by the Guarantor in trust for the Beneficiary and will be turned over to the Beneficiary in the exact form received by the Guarantor, to be applied against the Guaranteed Obligations in such order as the Beneficiary may determine in its sole discretion.

Contribution, Indemnification, Reimbursement. The Guarantor hereby irrevocably and absolutely waives all right of contribution, indemnification, reimbursement or similar rights against the Company with respect to the Guaranty, whether such rights arise under an express or implied contract or by operation of law, it being the intention of the Guarantor and the Company that the Guarantor will not be deemed to be a "creditor" (as defined in Section 101 of the U.S. Bankruptcy Code or any other applicable law) of the Company by reason of the existence of this Guaranty if the Company becomes a debtor in any proceeding under the U.S. Bankruptcy Code or any other applicable law.

Agreement regarding Bankruptcy of Company. So long as any Guaranteed Obligations are owed to the Beneficiary, the Guarantor may not, without the prior written consent of the Beneficiary, commence, or join with any other person in commencing, any bankruptcy, reorganization or insolvency proceeding against the Company.

REPRESENTATIONS AND WARRANTIES

The Guarantor hereby represents and warrants as follows:

Organization. The Guarantor is a [_____] duly organized, validly existing and in good standing under the laws of the state of [_____].

Authorization; No Conflict. The execution and delivery by the Guarantor of this Guaranty, and the performance by the Guarantor of its obligations hereunder (i) are within the Guarantor's [_____] powers, (ii) have been duly authorized by all necessary [_____] action, (iii) do not contravene its [_____] or any law or regulation applicable to or binding on the Guarantor or any of its properties and (iv) do not require the consent or approval of any person that has not already been obtained or the satisfaction or waiver of any conditions precedent to the effectiveness of this Guaranty that have not been satisfied or waived.

Enforceability. This Guaranty constitutes the legal, valid and binding obligation of the Guarantor enforceable against the Guarantor in accordance with its terms, except to the extent that such enforceability may be limited by applicable bankruptcy, insolvency, dissolution, reorganization, moratorium, liquidation or other similar laws affecting creditors' rights generally and by general principles of equity (regardless of whether enforcement is sought in a proceeding in equity or at law).

No Bankruptcy Proceedings. There are no bankruptcy proceedings pending or being contemplated by Guarantor or, to its knowledge, threatened against it.

No Legal Proceedings. There are no legal proceedings that would be reasonably likely to materially adversely affect Guarantor's ability to perform this Guaranty.

MISCELLANEOUS

Continuing Guaranty; Assignment. This Guaranty is a continuing guaranty and will (i) remain in full force and effect until all of the Guaranty Obligations have been satisfied, (ii) consistent with the terms hereof, apply to all Guaranteed Obligations whenever arising, (iii) be binding upon the Guarantor, its successors and assigns, and (iv) inure to the benefit of, and be enforceable by, the Beneficiary and its permitted assignees hereunder. The Guarantor may not assign or delegate its rights or obligations under this Guaranty without (x) the prior written consent of the Beneficiary, which consent may be withheld in the Beneficiary's sole discretion, and (y) a written assignment and assumption agreement in form and substance reasonably acceptable to the Beneficiary. Without prejudice to the survival of any of the other agreements of the Guarantor under this Guaranty, the agreements and obligations of the Guarantor contained in Section 4.4 (with respect to enforcement expenses) and the last sentence of Section 2.2(a) will survive the payment in full of the Guaranteed Obligations and all of the other amounts payable under this Guaranty.

Notices. All notices, requests, demands and other communications that are required or may be given under this Guaranty will be in writing and will be deemed to have been duly given when actually received if (a) personally delivered; (b) transmitted by facsimile, electronic or digital transmission method; or (c) if sent by certified or registered mail, return receipt requested. In each case notice will be sent:

(i) if to the Beneficiary:

[Company, address, c/o person]

(ii) if to the Guarantor:

[Company, address, c/o person]

or to such other place and with such other copies as the Beneficiary or the Guarantor may designate as to itself by written notice to the other pursuant to this Section 4.2. Delivery by facsimile or other electronic or digital method of an executed counterpart of a signature page to any amendment or waiver of any provision of this Guaranty will be effective as delivery of an original executed counterpart thereof.

Delay and Waiver. No failure on the part of the Beneficiary to exercise, and no delay in exercising, any right hereunder will operate as a waiver thereof; nor will any single or partial exercise of any right hereunder preclude any other or further exercise thereof or the exercise of any other right. The remedies herein provided are cumulative and not exclusive of any remedies provided by law.

Expenses. The Guarantor agrees to pay or reimburse the Beneficiary and any permitted assignees of the Beneficiary on demand for its reasonable costs, charges and expenses (including reasonable fees and expenses of counsel) incurred in connection with the enforcement of this Guaranty or occasioned by any breach by the Guarantor of any of its obligations under this Guaranty, including without limitation any actions taken in any bankruptcy or insolvency proceedings, should Guarantor be required to pay under this Guaranty.

Entire Agreement; Amendments; Other Guarantees. This Guaranty and any agreement, document or instrument attached hereto or referred to herein integrate all the terms and conditions mentioned herein or incidental hereto and supersede all oral negotiations and prior writings in respect to the subject matter hereof. In the event of any conflict between the terms, conditions and provisions of this Guaranty and any such agreement, document or instrument, the terms, conditions and provisions of this Guaranty will prevail. This Guaranty may only be amended or modified by an instrument in writing signed by each of the

Guarantor and the Beneficiary and any permitted assignees of the Beneficiary. Without limiting the foregoing: (i) this Guaranty will not release, modify, revoke or terminate any other guaranty heretofore, now or hereafter executed by the Guarantor; nor will any other guaranty heretofore, now or hereafter executed by the Guarantor release, modify, revoke or terminate this Guaranty, and (ii) all of the Guarantor's liabilities and obligations and the Beneficiary's rights and remedies under this Guaranty are in addition to and cumulative with those under any other guaranty executed by the Guarantor in favor of the Beneficiary or any affiliate of the Beneficiary on or about the date hereof or at any other time.

Headings. The headings of the various Sections of this Guaranty are for convenience of reference only and will not modify, define or limit any of the terms or provisions hereof.

Governing Law; Consent to Jurisdiction. This Guaranty will be construed and interpreted, and the rights of the parties determined, in accordance with the law of the state of Georgia, without giving effect to principles of conflicts of law that would require the application of the laws of another jurisdiction.

Each party hereto irrevocably and unconditionally (i) agrees that the exclusive jurisdiction for any suit, action or other legal proceeding arising out of this Guaranty will be brought in the United States District Court for the Northern District of Georgia or in any Georgia State court of general jurisdiction in Fulton County, Atlanta, Georgia; (ii) consents to the jurisdiction of any such court in any such suit, action or proceeding; and (iii) waives any objection that such party may have to the laying of venue of any such suit, action or proceeding in any such court.

THE GUARANTOR HEREBY IRREVOCABLY WAIVES ALL RIGHT TO TRIAL BY JURY IN ANY ACTION, PROCEEDING OR COUNTERCLAIM (WHETHER BASED ON CONTRACT, TORT OR OTHERWISE) ARISING OUT OF OR RELATING TO, THIS GUARANTY, OR THE ACTIONS OF THE BENEFICIARY IN THE NEGOTIATION, ADMINISTRATION, PERFORMANCE OR ENFORCEMENT THEREOF.

Severability. Any provision of this Guaranty that is prohibited or unenforceable will be ineffective to the extent of such prohibition or unenforceability without invalidating the remaining provisions hereof.

IN WITNESS WHEREOF, the Guarantor has caused this Guaranty to be duly executed and delivered by its duly authorized representative as of the day and year first above written.

[Company]

Attest: _____ By: _____

Name: _____ Name: _____

Title:___ Title:___

APPENDIX J

GUARANTEED HEAT RATES

There shall be a Guaranteed Heat Rate established for operation on Natural Gas based on the following formula and the ABC coefficients set forth below.

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REDACTED

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Energy produced by Seller and delivered to Buyer from synchronization to Minimum Capacity and from Minimum Capacity to offline will be paid for at the Guaranteed Heat Rate at Minimum Capacity.

APPENDIX K

RESERVED

APPENDIX L

CERTIFICATION OF WHETHER THE AGREEMENT WILL REQUIRE DECONSOLIDATION BY SELLER WITH RESPECT TO VARIABLE INTEREST ENTITY

AGREEMENT – Power Purchase Agreement dated _____ ___, 20__ between Georgia Power Company ("Buyer"), and _____ ("Seller") (the "Agreement"). Capitalized terms used herein shall have the meaning assigned in the Agreement.

The undersigned individual, being chief financial officer or another duly authorized officer of Seller and having responsibilities for financial accounting matters associated with the Agreement, hereby certifies that the Agreement WILL (_____)/WILL NOT (_____) require Seller, at any time over the Agreement Term and based on U.S. Generally Accepting Accounting Principles in effect as of the date of this certificate, to deconsolidate on its books and records any assets, liabilities, cash flow, profits or losses of Seller as a result of the Georgia Power being determined to be the Primary Beneficiary. My determination of the most likely accounting treatment of this transaction results from my personal consideration after necessary discussions with relevant officers of Accounting Standards Codification ("**ASC**") Topic 810, Consolidation, and the following factual matters:

1) Seller's accounting policies, procedures, and internal controls are sufficient to provide Georgia Power with an appropriate basis for confirming the information contained herein.

   _____Yes
   _____No (please explain)

   *Explain:*_____
   _____
   _____
   _____

2) Seller qualifies for one of the scope exceptions listed in paragraphs 810-10-15-12 and 810-10-15-17 of ASC Topic 810.

   _____Yes (please explain)
   _____No

   *Explain:*_____
   _____
   _____
   _____

3) Seller is financed with equity equal to or greater than ten percent (10%) of Seller's total assets per paragraphs 810-10-25-45 to 47 of ASC Topic 810.

   _____ Yes
   _____No

4) The Agreement revenues correlate with fluctuations in Seller's operating cash flows (operating expenses).

_____ Yes (please explain)
_____No

*Explain:*_____
_____
_____
_____

5) The Agreement reduces variability in the fair value of Seller's assets, for example by absorbing fuel or electricity price risk.

_____ Yes (please explain)
_____ No

*Explain:*_____
_____
_____
_____

6) The Agreement Term is for greater than 50% of the remaining economic life of the unit.

_____ Yes
_____No

7) The Agreement is for substantially all of the proposed Facility's productive output.

_____Yes
_____ No

8) Georgia Power and/or its affiliates participated significantly in the design or redesign of the Facility.

_____Yes
_____ No

9) The percentage that the Facility's fair value represents, of the fair value of the proposed Seller's total assets, is approximately;

_____%

10) The Facility is essentially the only source of payment for specified liabilities or specified other interest (there is specific debt associated with the Facility).

_____Yes
_____ No

Confirmation

The above information (and any attachments) has been completed in full and agrees with our records as of the date hereof.

By: _____

Title: _____

Company: _____

Date: _____

APPENDIX M

CERTIFICATION AS TO CERTAIN FACTUAL STATEMENTS RELATED TO THE PROPOSED TRANSACTION WITH RESPECT TO FINANCE LEASE TREATMENT

*(While completion of this certification is a requirement, the assertions herein are relevant only if a lease is identified in accordance with Accounting Standard Codification ("**ASC**") Topic 842, Leases.)*

AGREEMENT – Agreement for the Purchase of Energy, Environmental Attributes and Electrical Products from a Renewable Resource dated _____ ___, 20__ between Georgia Power Company ("**Georgia Power**") and _____ ("**Seller**") (the "**Agreement**"). Capitalized terms used herein will have the meaning assigned in the Agreement.

The undersigned individual, being chief financial officer or another duly authorized officer of _____ and **[having responsibilities/based on information I have received from individuals responsible]** for financial accounting matters arising from this Agreement, based on my personal consideration after necessary discussions with relevant officers of factual matters hereby certifies the following based on my understanding of ASC Topic 842, Leases.

1. The Agreement DOES (_____)/DOES NOT (_____) transfer ownership of the Facility at or by the end of the Agreement Term as described in paragraph 842-10-25-2(a) of ASC Topic 842.

2. The Agreement DOES (_____)/DOES NOT (_____) contain a purchase option for the Facility that is reasonably certain to be exercised as described in paragraph 842-10-25-2(b) of ASC Topic 842.

3. The Agreement Term IS (_____)/IS NOT (_____) equal to the major part or seventy-five percent (75%) or more of the estimated remaining economic life of the Facility offered as described in paragraph 842-10-25-2(c) of ASC Topic 842.

4. The present value of the minimum lease payments allocated to the Facility at the beginning of the Agreement Term IS (_____)/IS NOT (_____) greater than or equal to substantially all or ninety percent (90%) of the fair value of the Facility offered as described in paragraph 842-10-25-2(d) of ASC Topic 842.

5. The Facility IS (_____)/IS NOT (_____) of such a specialized nature that it is expected to have no alternative use to the lessor at the end of the Agreement Term as described in paragraph 842-10-25-2(e) of ASC Topic 842.

If I have responded in the affirmative to one or more of the above factual statements, I have attached a good faith statement of the dollar amounts that the Company would be required to capitalize and the residual value of the Facility at the end of the Term.

The Seller understands that the Buyer will rely upon this certification, and that the Buyer may require further documentation supporting this certification.

Confirmation

The above information (and any attachment) agrees with Seller's records as of the date hereof.

By: _____

Title: _____

Company: _____

Date: _____

APPENDIX N

TRANSFER OF INFORMATION ACKNOWLEDGEMENT

_____("**Seller**") and Georgia Power Company ("**Georgia Power**") have entered into that certain Power Purchase Agreement ("**Agreement**") dated as of _____, 202__. The Agreement contemplates that certain information that could be considered to be non-public information that potentially has implications under the Federal Energy Regulatory Commission's Standards of Conduct will be provided by Seller to Georgia Power and/or Southern Company Services, Inc. as agent for the transmission owning subsidiaries of Southern Company (Alabama Power Company, Georgia Power Company, and Mississippi Power Company). Seller acknowledges that such information is being provided for the purposes of operational implementation and administration of the Agreement (which includes conducting Georgia Power Company's system operations and dispatch functions) and will be utilized by individuals in both Transmission/Distribution and energy affiliate/wholesale marketing unit functions under the Standards of Conduct.

The individuals within the Southern Company organizations indicated above may only use the information for the purpose of implementing and administering the Agreement (including conducting Georgia Power's system operations and dispatch functions). Seller understands that such information will not be used or disseminated in any manner contrary to the confidentiality provision(s) in the Agreement or in violation of the Federal Energy Regulatory Commission's Standards of Conduct. Seller's provision of this information has not been and is not being provided in exchange for any preferential treatment, either operational or rate-related, by Southern Company Services, Inc. or by any of the transmission-owning subsidiaries of Southern Company. Seller also acknowledges that Seller is not providing the information under duress or coercion. In accordance with requirements of the Federal Energy Regulatory Commission, Southern Company Services, Inc. may post on OASIS the fact of Seller's consent to the provision of the information specified above to certain employees that may be employed within organizational units deemed to be energy affiliates/wholesale marketing units under the Standards of Conduct.

Acknowledged on behalf of Seller:

By: _____

Name: _____

Title: _____

Date: _____

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Technical Information Supporting the Potential Acquisition of an Additional Ownership Interest in an Existing Generating Asset

Summary

Georgia Power Company ("Georgia Power" or the "Company") is pursuing the option to acquire an additional ownership interest in an existing generating resource within the Southern Company footprint. Because negotiations are ongoing, the name of the generating resource is not disclosed in the Main Document of the 2023 Integrated Resource Plan ("IRP") Update. The purpose of this report is to provide technical information under Trade Secret protection to support the Commission's review and approval of the potential acquisition. The generating assets under consideration for acquisition by the Company are **REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED.** The following sections provide information pertaining to the resources and the potential acquisition.

Resource Information

**REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED

REDACTED REDACTED REDACTED

Technical Information Supporting the Proposal to Develop 178 MW of Battery Energy Storage Systems at Robins and Moody Air Force Bases

Summary

Georgia Power Company ("Georgia Power" or the "Company") is requesting authority to develop, own, and operate up to 1,000 MW of Battery Energy Storage Systems ("BESS") in its 2023 Integrated Resource Plan ("IRP") Update. Approximately 178 MW of BESS resources are proposed to be added to existing Company-owned solar facilities at Robins and Moody Air Force Bases located in Houston and Lowndes Counties, respectively. By utilizing charging from the existing solar resources and leveraging existing interconnection facilities, the new BESS resources could achieve commercial operation by November 2026 and meet capacity needs beginning in the winter of 2026/2027. This report provides additional technical information to support the Company's proposal to develop these BESS resources at existing Company-owned solar sites. If approved by the Georgia Public Service Commission ("Commission"), the Company will return to the Commission after executing a Battery and Equipment Supply Agreement ("BESA") and an Engineering, Procurement, and Construction ("EPC") agreement and will request certification of these BESS resources at that time.

Technology

The Company proposes to add approximately 178 MW of 4-hour duration lithium iron phosphate ("LFP") BESS to existing Company-owned solar facilities – 128 MW at the Robins Air Force Base solar facility and 49.5 MW at the Moody Air Force Base solar facility. To facilitate quick deployment, the proposed BESS resources will utilize existing solar interconnections and will be charged primarily by the existing solar resources. The BESS will, however, maintain flexibility to grid-charge if deliverability constraints are not present on the transmission system.

The BESS projects will incorporate LFP battery cell technology and power conversion systems provided by reputable manufacturers. The Company is currently engaged with multiple suppliers to manage their committed volume and lead times for these projects and other contracted projects with similar construction timelines. These projects will leverage current relationships with top market suppliers to procure timely and reliable BESS equipment. The Company has focused on developing relationships with trusted suppliers that understand and are able to stand behind construction and operational guarantees to ensure successful project deployment. Figure 1 below provides additional project details and estimated performance metrics for the proposed BESS resources.

Figure 1 - Details & Estimated Performance Metrics for Robins & Moody BESS

	Robins	Moody
Location	Warner Robins, GA	Valdosta, GA
Commercial Operation Date	November 2026	November 2026
Battery Chemistry	LFP	LFP
Capacity (MW)	128	49.5
Duration (hours)	4	4
Energy Capacity (MWh)	512	198
Asset Life (years)	20	20
Round-Trip Efficiency (%)	85	85

Schedule

Figure 2 summarizes the project schedule, including estimated start dates for major milestones necessary to achieve November 2026 Commercial Operation Dates ("COD"). Estimated milestone dates are subject to change and will be updated through the project development process. Due to similar timelines, the schedule below is applicable to both Robins and Moody BESS.

After filing the 2023 IRP Update, the Company will begin selecting vendors and negotiating the BESA and the EPC agreement. The scope of the BESA will encompass the batteries and most major equipment. The scope of the EPC agreement will be more focused on engineering, construction, and procurement of equipment not covered by the BESA. Execution for all major contracts is planned for completion by the third quarter of 2024. As contract negotiations are ongoing, the Company will begin identification and procurement of long-lead items to manage the critical path of the projects. BESS construction activities are set to begin by the fourth quarter of 2025 with COD to occur by November 2026 to support meeting capacity needs for the winter of 2026/2027. The 12-month construction window includes civil, electrical, and mechanical construction and delivery, installation, testing, and commissioning of all equipment onsite.

Figure 2 - Estimated Project Schedule for Robins & Moody BESS

REDACTED

Estimated Cost

A summary of preliminary cost estimates for the Robins and Moody BESS resources is provided in Figure 3. Costs are subject to change pending execution of the BESA and the EPC agreement. Economic analyses for these resources are found in the Economic Analysis of Capacity Resources document in the Technical Appendix. The economic analysis and associated workpapers contain information on the Company's financing cost, assumed spending curves, plant operating costs, and other information impacting the revenue requirement for the proposed BESS resources.

Figure 3 - Estimated Costs for Robins & Moody BESS

	Robins	Moody
Overnight Costs (millions of dollars)	**REDACTED**	**REDACTED**
In-Service Capital (millions of dollars)	**REDACTED**	**REDACTED**

Inflation Reduction Act

On August 16, 2022, President Biden signed Public Law 117-369, 136 Stat. 1818, commonly known as the Inflation Reduction Act ("IRA") of 2022, into law. The Inflation Reduction Act's incentives for energy storage projects in the United States took effect in January 2023. The passing of this law allows for standalone energy storage projects to qualify for investment tax credits ("ITCs"). Prior to the passing of the IRA, standalone energy storage projects only qualified for ITCs if exclusively charged from a solar facility.

Energy storage projects that commence construction after January 1, 2023, will receive a 6% ITC. If a project satisfies the prevailing wage and apprenticeship ("PWA") requirements, it receives a bonus credit of 24% and will qualify for the full 30% ITC. For the proposed Robins and Moody BESS resources, the base assumption is that these projects will meet the PWA requirements and qualify for the 30% ITC benefit.

Conclusion

The proposed Robins and Moody BESS projects utilize existing land, equipment, and agreements to streamline development and commercial operation of reliable, dispatchable resources. These assets will meet capacity needs beginning in winter of 2026/2027 and will benefit Georgia Power's customers for many years to come. If approved by the Commission, the Company will return to the Commission after executing the BESA and the EPC agreement and will request certification of these BESS resources.

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Technical Information Supporting the Proposal to Develop 200 MW of Battery Energy Storage Systems Co-located with 200 MW of New Solar

Project Summary

Georgia Power Company ("Georgia Power" or the "Company") is presently in negotiations with **REDACTED REDACTED** ("Seller") for the acquisition and construction of solar and battery energy storage systems ("BESS") facilities at a site located in REDACTED REDACTED, Georgia. Seller or its affiliated entities have obtained through lease approximately REDACTED acres of real property, much of which has been permitted for solar and BESS facilities. The Company is seeking to acquire and construct an approximately 200 MW alternating current ("AC") solar facility and an AC-coupled 200 MW/800 MWh BESS on a portion of the above-referenced property, which is under lease by Seller or its affiliates (the "Project"). **REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED.**

**REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED

applicable provisions of the Inflation Reduction Act. **REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED.**

Estimated Cost

Based on initial indicative pricing from Seller and incorporating owner's costs, the Company expects an estimated overnight cost of $**REDACTED REDACTED**, which excludes financing costs. For the EPC Agreement, Georgia Power has received a proposal that the pricing under the EPC Agreement be "open book" until NTP, which means the Contractor will guarantee a fixed price upon NTP. The Project is still subject to review and negotiation by Georgia Power and Seller.

Technical Information Supporting the Proposal to Develop up to 1,400 MW from Three Simple Cycle Combustion Turbines at Plant Yates

Summary

Georgia Power Company ("Georgia Power" or the "Company") is requesting authority to develop, own, and operate up to 1,400 MW of advanced frame, dual-fuel simple cycle combustion turbine ("CT") resources in its 2023 Integrated Resource Plan ("IRP") Update. Three dual-fuel CTs are proposed to be located at Plant Yates, an existing Company-owned plant in Coweta County, Georgia, which is currently home to two converted natural gas steam units – Plant Yates Units 6&7. Following existing naming convention, the new dual-fuel CTs would constitute Plant Yates Units 8-10. Under the proposed schedule, the CT resources could achieve commercial operation by December 1, 2026, for Units 8 and 9, and April 1, 2027, for Unit 10. This report provides additional technical information to support the Company's proposal to develop the three CTs. If approved by the Georgia Public Service Commission ("Commission"), the Company will return to the Commission after executing an Engineering, Procurement, and Construction ("EPC") agreement and will request certification of the CT resources.

Technology

The proposed project would utilize three, dual-fuel capable **REDACTED REDACTED** CTs. This technology consists of a high-efficiency compressor, combustor, and high-efficiency turbine that works in the following manner. First, the inlet air is filtered and then compressed in a multiple stage axial flow compressor. The compressed air and fuel are mixed and combusted in the turbine combustion chamber. Hot exhaust gases from the combustion chamber expand through a multi-stage power turbine that results in energy to drive both the air compressor and electric power generator. Advancements in CT design and exhaust gas temperature management enable the simple cycle units to be fitted with catalyst systems to reduce emissions. Each CT will have a winter output of approximately REDACTED MW when firing on natural gas and REDACTED MW on fuel oil. The proposed project would be designed to have a 45-year asset life. Figure 1 provides additional estimated performance metrics for the proposed project.

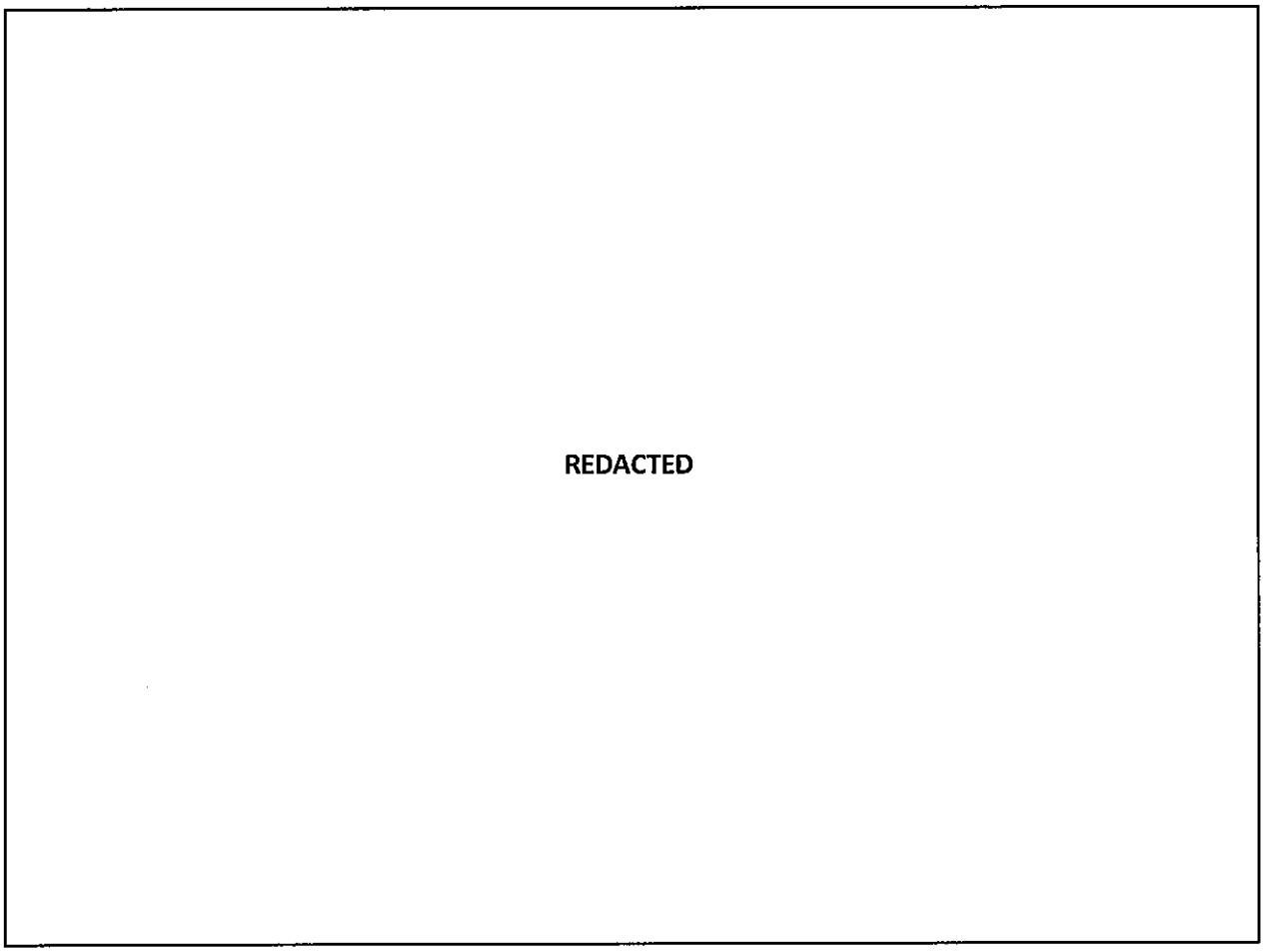
Figure 1 - Estimated Performance Metrics for Plant Yates Units 8-10

	Natural Gas	Fuel Oil
Winter Capacity (MW)	**REDACTED**	**REDACTED**
Summer Capacity (MW)	**REDACTED**	**REDACTED**
Winter Heat Rate (Btu/kWh)	**REDACTED**	**REDACTED**
Summer Heat Rate (Btu/kWh)	**REDACTED**	**REDACTED**

Schedule

To meet significant capacity needs beginning in the winter of 2026/2027, certain development and long-lead-time procurement activities related to the three proposed CTs at Plant Yates must commence as early as fourth quarter 2023. Figure 2 summarizes the project schedule, including estimated start dates for major milestones necessary to achieve the required Commercial Operation Date ("COD") for each unit. Estimated milestone dates are subject to change pending execution of a final EPC agreement and commencement of site work.

Figure 2 - Estimated Project Schedule for Plant Yates Units 8-10



Estimated Cost

A summary of preliminary cost estimates for Plant Yates Units 8-10 is provided in Figure 3. Costs are subject to change pending execution of a final EPC agreement. Economic analyses for Plant Yates Units 8-10 are found in the Economic Analysis of Capacity Resources document in the Technical Appendix. The economic analysis and associated workpapers contain information on the Company's financing cost, assumed spending curves, plant operating costs, and other information impacting the revenue requirement for the proposed CTs.

Figure 3 - Estimated Costs for Plant Yates Units 8-10

Overnight Cost (millions of dollars)	**REDACTED**
In-Service Capital (millions of dollars)	**REDACTED**

Conclusion

The proposed CT resources are designed to provide reliable, dispatchable power to meet significant capacity needs beginning in the winter of 2026/2027. These advanced high-efficiency turbines will benefit Georgia Power's customers for many years to come. If approved by the Commission, the Company will return to the Commission upon execution of a final EPC agreement and request certification of Plant Yates Units 8-10.

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2023 IRP Update Load and Energy Forecast

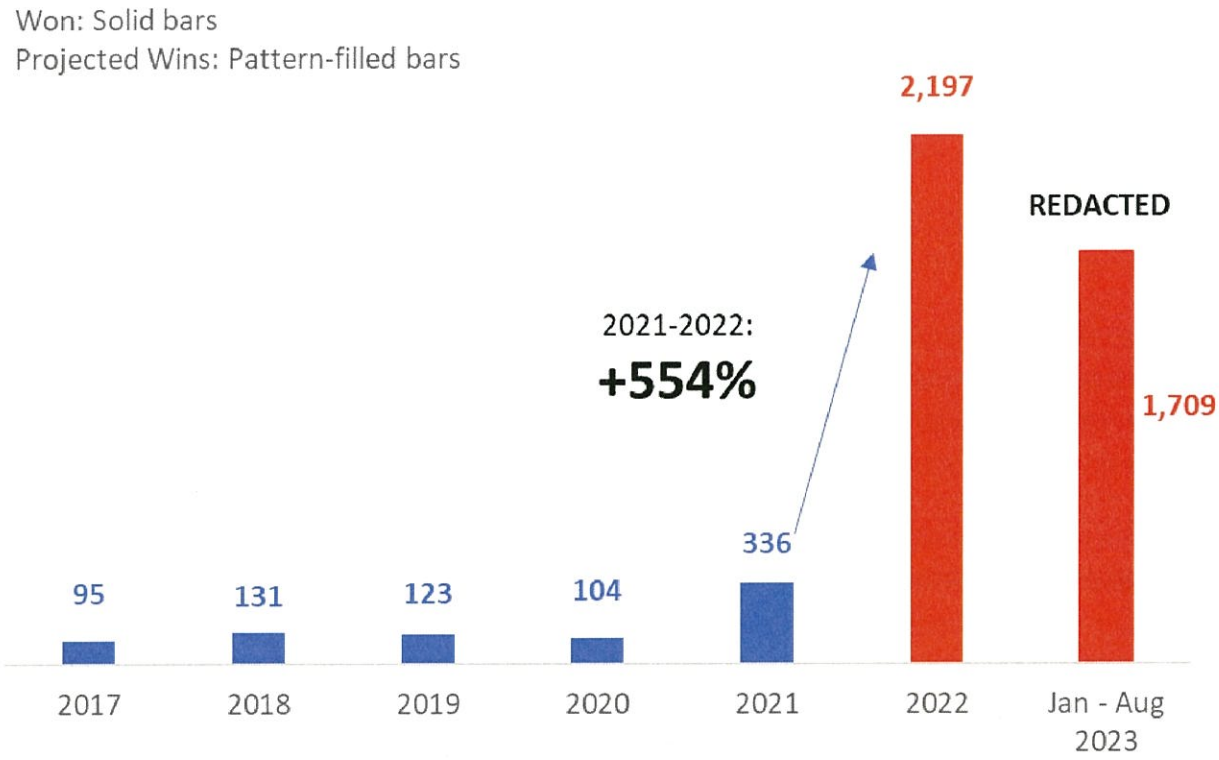
1.0 Executive Summary Overview

In support of the 2023 Integrated Resource Plan ("IRP") Update, this document presents the 2023 IRP Update Load and Energy Forecast ("2023 IRP Update Load Forecast").

The 2023 IRP Update Load Forecast provides a twenty-year forecast of energy sales and peak demand to meet the planning needs of Georgia Power Company ("Georgia Power" or the "Company"). The 2023 IRP Update Load Forecast includes the following retail classes: residential; commercial; industrial; Metropolitan Atlanta Rapid Transit Authority ("MARTA"); and governmental lighting.

Georgia has seen unprecedented growth in economic development activity since Georgia Power's 2022 Integrated Resource Plan. Numerous new businesses and industries have come to Georgia, including significant new load related to manufacturing, clean energy technology, and data centers. This growth falls outside of the historical norms in terms of both the size and speed of development, with some projects surpassing 1,000 MW. As reflected in Figure 1.0-1, large load projects that Georgia Power was selected to serve in 2022 represented almost 2,200 MW. This is more than six times greater than in 2021 and nearly 22 times greater than the approximately 100 MW of large load the Company was selected to serve per year from 2017 to 2020. This growth has sustained in 2023. From January through August 2023, the Company was selected to serve more than 1,700 MW of new customer load and total Company selections in 2023 are estimated to be more than **REDACTED** MW.

Figure 1.0-1: New Large Load Customers Selecting Georgia Power by Year (MW)



Large load projects for calendar year 2022 forward have been characterized by two prominent features:

- **Large Size**: Many projects, especially data centers, have load greater than 100 MW and may even reach 1,000+ MW.
- **Dynamic Project Specifications**: Project specifications frequently change in terms of location, commercial operation date ("COD"), and load ramp-up.

The load forecast must account for several project uncertainties, including state selection, electric provider selection, project delays, and load materialization. If the Company does not account for new large customer loads before project initiation, the Company risks underestimating the need for generating capacity to reliably serve customers. On the other hand, the Company must take a measured approach that avoids overestimating the resources needed to serve customers and the costs associated with surplus resources.

To balance its projections, the Company has developed a probabilistic approach to evaluate the range and likelihood of potential load growth from new large load customers. This balanced approach is evidenced by the external adjustments applied to the Company's updated baseline load and energy forecast. The methodology used to develop external adjustments is discussed in detail in Section 1.5 below.

1.1 SUMMER AND WINTER PEAK DEMAND

Georgia Power has produced a forecast of both summer and winter peak demand since the Budget 2019 forecast, which was used in the 2019 IRP. The Company's all-time peak demand of 17,985 MW occurred on August 9, 2007. Georgia Power's highest winter peak demand of 16,308 MW occurred during a polar vortex on January 7, 2014.

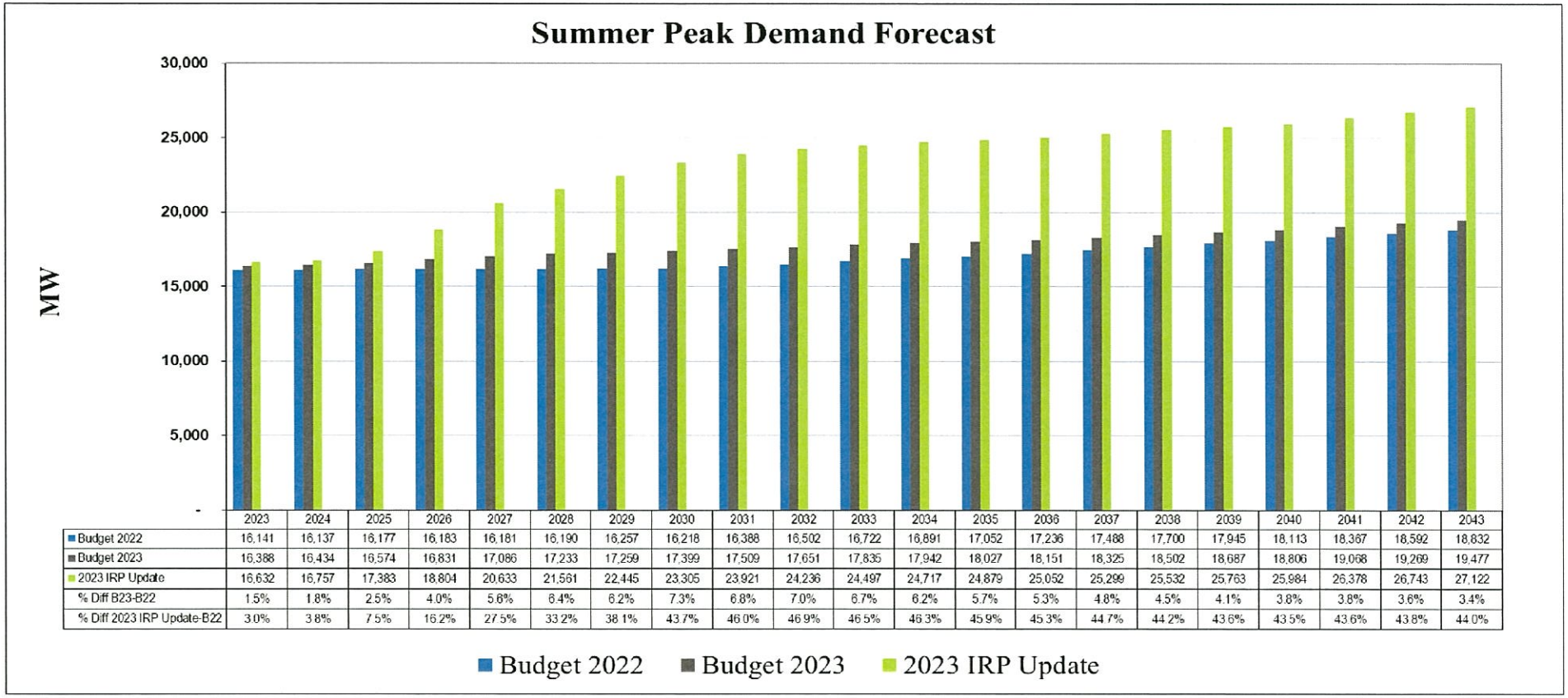
The summer and winter peak demand forecasts are based on normal weather. Both forecasts also include load represented by electric vehicles and behind-the-meter solar. In addition, Georgia Power has traditionally incorporated external adjustments to reflect the effects of the impacts of cogeneration and of company-sponsored Demand Side Management ("DSM") programs.

With the introduction of new load due to the extraordinary economic development taking place in Georgia, the Company established a new forecasting methodology to reflect the unique characteristics of the new loads and incorporate those characteristics, as appropriate, in the form of an additional external adjustment to its load forecast. Georgia Power currently anticipates a rapid increase in its summer and winter peak demands due to new loads expected in the Commercial and Industrial classes.

The probabilistic model the Company developed evaluates a hundred thousand potential combinations for existing and potential economic development loads. These combinations can be sorted and ranked by total MW and MWh to determine the probability of certain load levels. For example, the P50 value corresponds to the median load level within the range of potential outcomes. Similarly, P95 indicates a load level where 95% of all potential combinations fall at or below this level, and 5% of the load combinations fall above it. The 2023 IRP Update Load Forecast includes the P95 load value.

The high-level impacts on peak demands resulting from new large customer loads are presented in Figure 1.1-1 and 1.1-2. These charts contain a comparison of Budget 2022 peaks, which were used in the 2022 IRP, with the Budget 2023 Load and Energy Forecast ("Budget 2023") and the 2023 IRP Update Load Forecast.

Figure 1.1-1: Summer Peak Demand Forecast

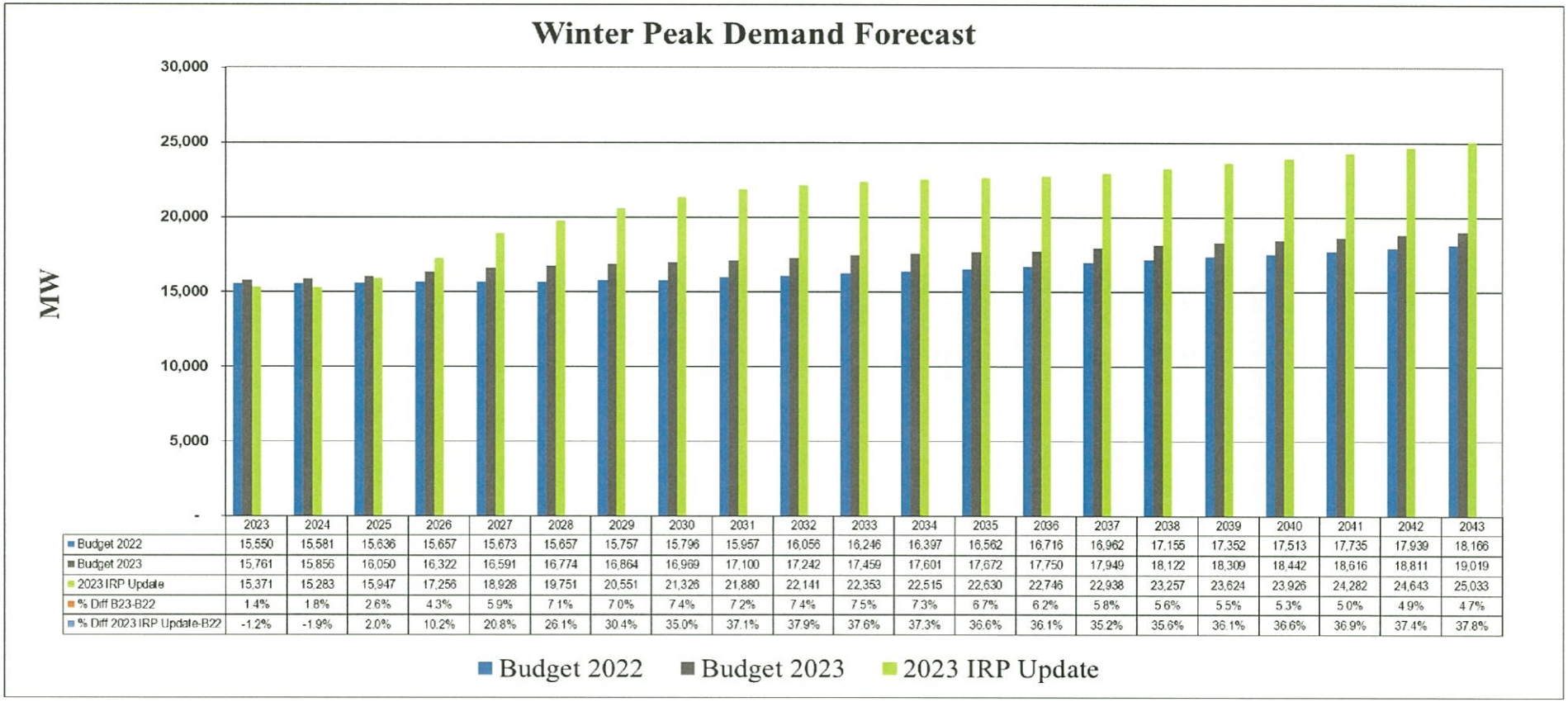


	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043
Budget 2022	16,141	16,137	16,177	16,183	16,181	16,190	16,257	16,218	16,388	16,502	16,722	16,891	17,052	17,236	17,488	17,700	17,945	18,113	18,367	18,592	18,832
Budget 2023	16,388	16,434	16,574	16,831	17,086	17,233	17,259	17,399	17,509	17,651	17,835	17,942	18,027	18,151	18,325	18,502	18,687	18,806	19,068	19,269	19,477
2023 IRP Update	16,632	16,757	17,383	18,804	20,633	21,561	22,445	23,305	23,921	24,236	24,497	24,717	24,879	25,052	25,299	25,532	25,763	25,984	26,378	26,743	27,122
% Diff B23-B22	1.5%	1.8%	2.5%	4.0%	5.6%	6.4%	6.2%	7.3%	6.8%	7.0%	6.7%	6.2%	5.7%	5.3%	4.8%	4.5%	4.1%	3.8%	3.8%	3.6%	3.4%
% Diff 2023 IRP Update-B22	3.0%	3.8%	7.5%	16.2%	27.5%	33.2%	38.1%	43.7%	46.0%	46.9%	46.5%	46.3%	45.9%	45.3%	44.7%	44.2%	43.6%	43.5%	43.6%	43.8%	44.0%

For the period from 2024 through 2031, the 2023 IRP Update Load Forecast reflects summer load growth of more than 7,100 MW. This is approximately 28 times greater than the Budget 2022 summer load growth of approximately 250 MW for the same period. It is nearly seven times greater than the Budget 2023 summer load growth of 1,075 MW for 2024-2031.

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Figure 1.1-2: Winter Peak Demand Forecast



	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043
Budget 2022	15,550	15,581	15,636	15,657	15,673	15,657	15,757	15,796	15,957	16,056	16,246	16,397	16,562	16,716	16,962	17,155	17,352	17,513	17,735	17,939	18,166
Budget 2023	15,761	15,856	16,050	16,322	16,591	16,774	16,864	16,969	17,100	17,242	17,459	17,601	17,672	17,750	17,949	18,122	18,309	18,442	18,616	18,811	19,019
2023 IRP Update	15,371	15,283	15,947	17,256	18,928	19,751	20,551	21,326	21,880	22,141	22,353	22,515	22,630	22,746	22,938	23,257	23,624	23,926	24,282	24,643	25,033
% Diff B23-B22	1.4%	1.8%	2.6%	4.3%	5.9%	7.1%	7.0%	7.4%	7.2%	7.4%	7.5%	7.3%	6.7%	6.2%	5.8%	5.6%	5.5%	5.3%	5.0%	4.9%	4.7%
% Diff 2023 IRP Update-B22	-1.2%	-1.9%	2.0%	10.2%	20.8%	26.1%	30.4%	35.0%	37.1%	37.9%	37.6%	37.3%	36.6%	36.1%	35.2%	35.6%	36.1%	36.6%	36.9%	37.4%	37.8%

The years in Figure 1.1-2 represent December of the year and January through February of the year shown. For the period from 2024 through 2031, the 2023 IRP Update Load Forecast reflects winter load growth of approximately 6,600 MW. This is approximately 17 times greater than the Budget 2022 winter load growth of approximately 400 MW for the same period. It is more than five times greater than the Budget 2023 winter load growth of approximately 1,250 MW for 2024-2031.

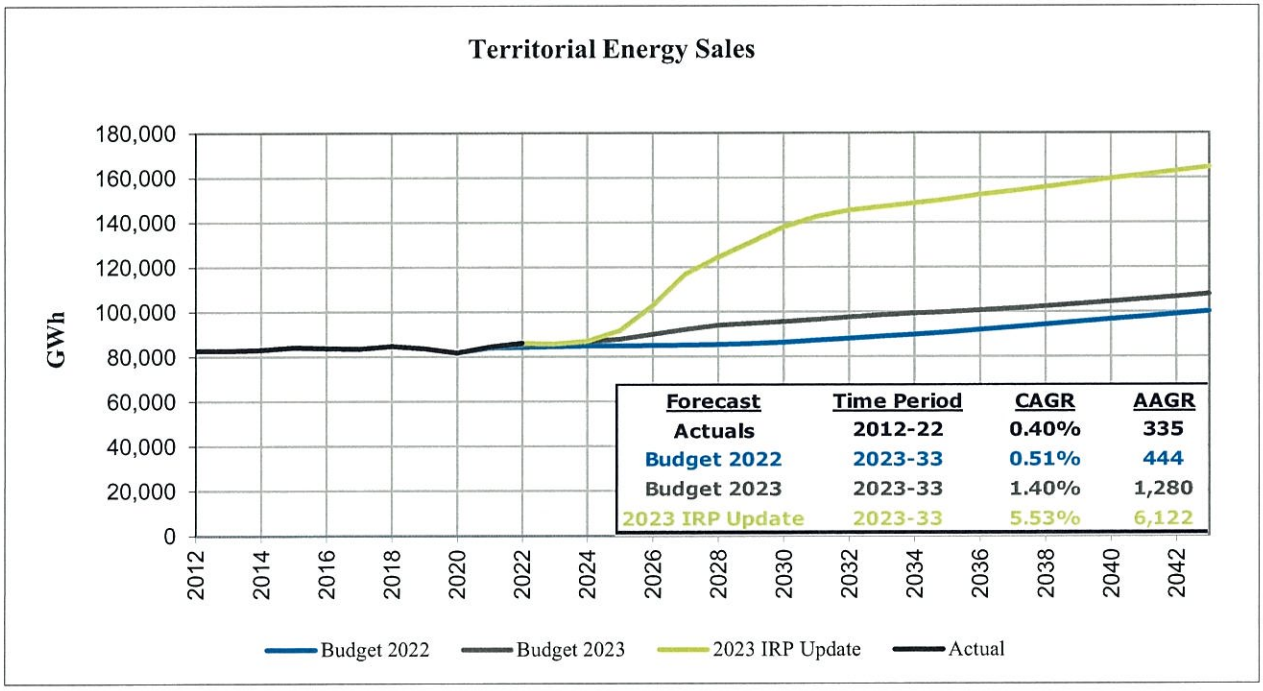
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1.2 ENERGY SALES

1.2.1 Territorial

Figure 1.2.1-1 shows the expected growth in territorial energy sales over the forecast horizon. In absolute terms, the amount of GWh growth is indicated by the average annual growth rate ("AAGR"). During the historical period from 2012 to 2022, which includes the Covid-19 pandemic, average growth increased by 335 GWh per year. The 2023 IRP Update Load Forecast anticipates an average growth of 6,122 GWh each year from 2023-2033, compared to Budget 2022 and Budget 2023 predicted growth of 444 GWh and 1,280 GWh per year, respectively, over this same period.

Figure 1.2.1-1: Territorial Energy Forecast



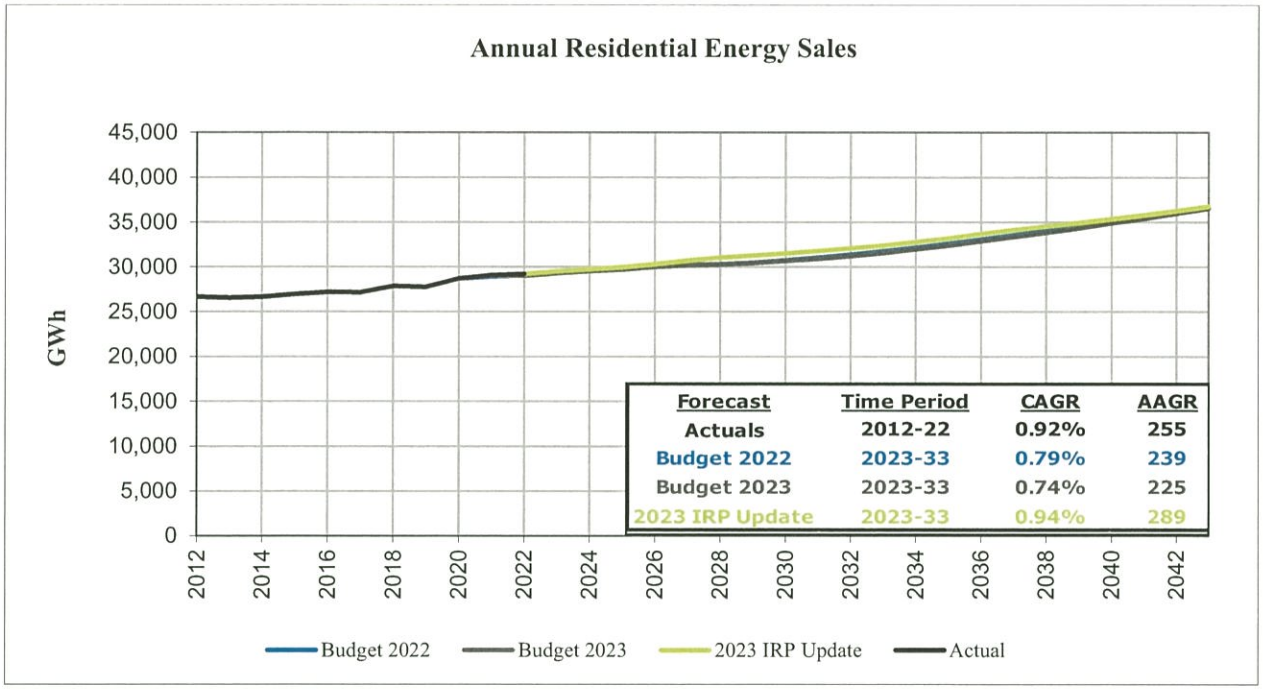
Forecast	Time Period	CAGR	AAGR
Actuals	2012-22	0.40%	335
Budget 2022	2023-33	0.51%	444
Budget 2023	2023-33	1.40%	1,280
2023 IRP Update	2023-33	5.53%	6,122

Territorial energy is a combination of the following classes: Residential, Commercial, Industrial, Governmental Lighting and MARTA. Understanding what is happening in the forecasts for each class thus provides insight into the total territorial forecast. The forecasts for each of these classes are discussed in the sections below.

1.2.2 Residential

Figure 1.2.2-1 shows the comparison of Budget 2022 and Budget 2023 with the 2023 IRP Update Load Forecast residential energy forecast. Over the 2012-2022 historical period, residential sales grew by an average rate of 255 GWh per year. The Budget 2022 forecast, which was completed during the Covid pandemic, had lower growth due to uncertainty about how quickly the economy and electricity sales would recover. Growth in the 2023 IRP Update Load Forecast is back in line with the historical rate and is above Budget 2022 and Budget 2023 over the forecast horizon, driven by robust growth in customers and higher expected growth in electric vehicles. Since the new large load activity only impacts the Commercial and Industrial classes, there is no additional external adjustment needed or applied to the baseline Residential, Governmental Lighting and MARTA classes.

Figure 1.2.2-1 Residential Energy Forecast

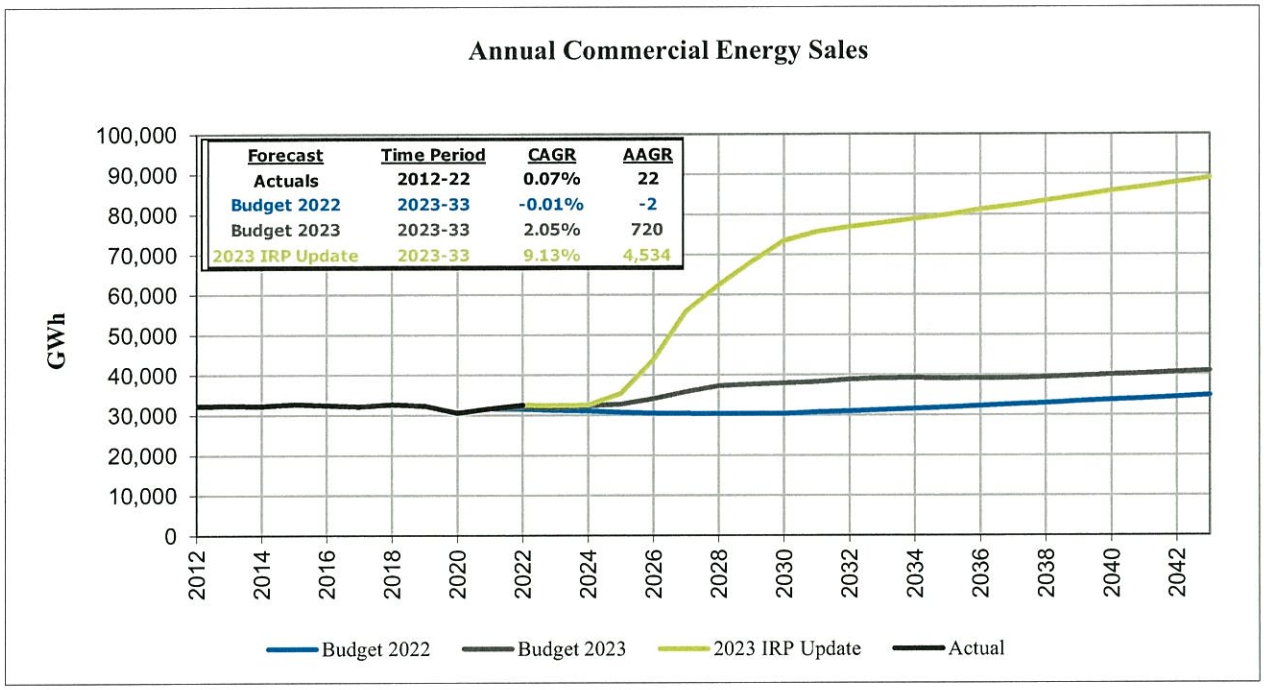


1.2.3 Commercial

From 2012-2022, average annual growth in commercial sales rose slightly, rising by an average of 22 GWh per year due in part to energy efficiency partially offsetting the impacts of customer growth. Budget 2022 projected annual declines in sales of 2 GWh from 2023-2033 before growth picks up in the outer years of the forecast, as seen in figure 1.2.3-1 below. The modest decline in sales through 2030 was driven primarily by continued growth in energy efficiency. In the latter years of the forecast, growth picks up due to expected growth in commercial square footage and electric vehicles. The 2023 IRP Update Load Forecast includes medium- and heavy-duty electric vehicles in addition to light-duty vehicles. The 2023 IRP Update Load Forecast begins to grow quickly beginning in 2025 as new large customer loads come

online, with sales expected to increase 4,534 GWh from 2023-2033. Growth in the 2023 IRP Update Load Forecast is even stronger over this period, increasing by 4,534 GWh per year. By 2030, expected sales in the 2023 IRP Update Load Forecast are more than double the expected GWh sales of Budget 2022.

Figure 1.2.3-1: Commercial Energy Forecast

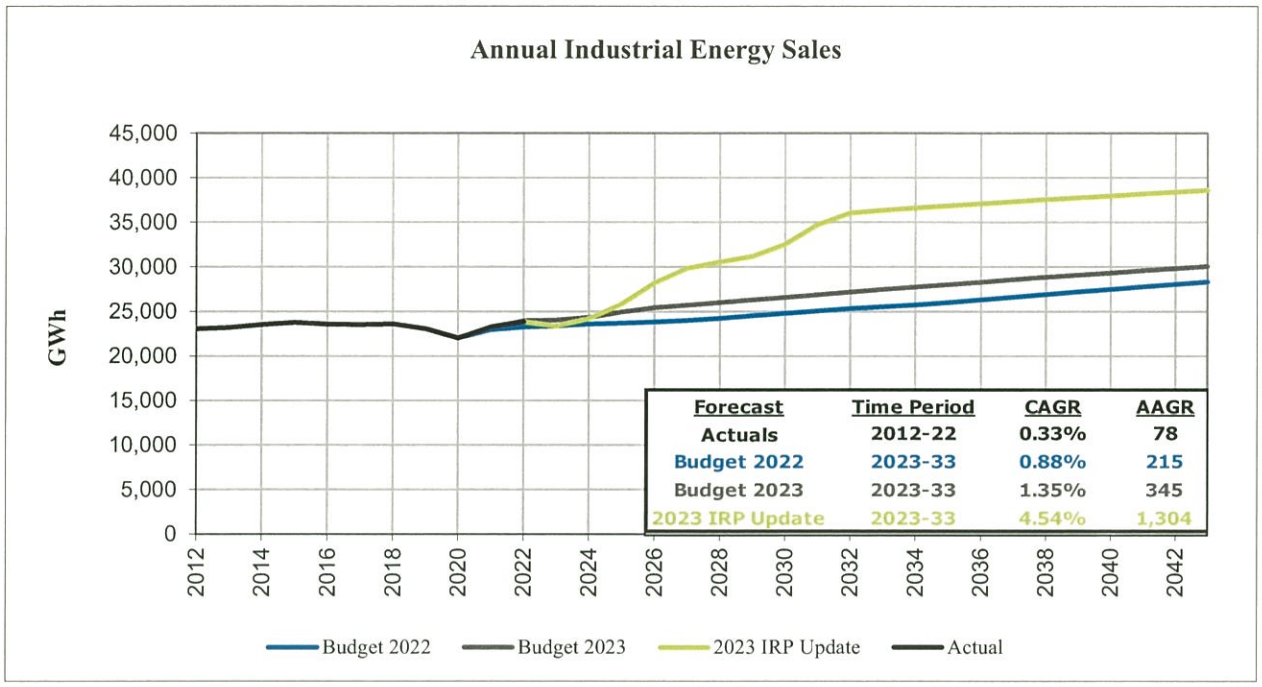


1.2.4 Industrial

Historical industrial sales from 2012-2022 rose by an average of 78 GWh per year. Figure 1.2.4-1 shows a comparison of Budget 2022, Budget 2023 and the 2023 IRP Update Load Forecast.

Industrial sales in Budget 2022 were expected to grow slowly after the pandemic, and then pick up in the outer years of the forecast, driven primarily by growth in Industrial Production. The 2023 IRP Update Load Forecast begins to grow quickly in 2025 and beyond as new large customer load projects come online. Over the 2023-2033 period, the 2023 IRP Update Load Forecast is expected to add 1,304 GWh per year compared to just 215 GWh per year in Budget 2022 and 345 GWh per year in Budget 2023.

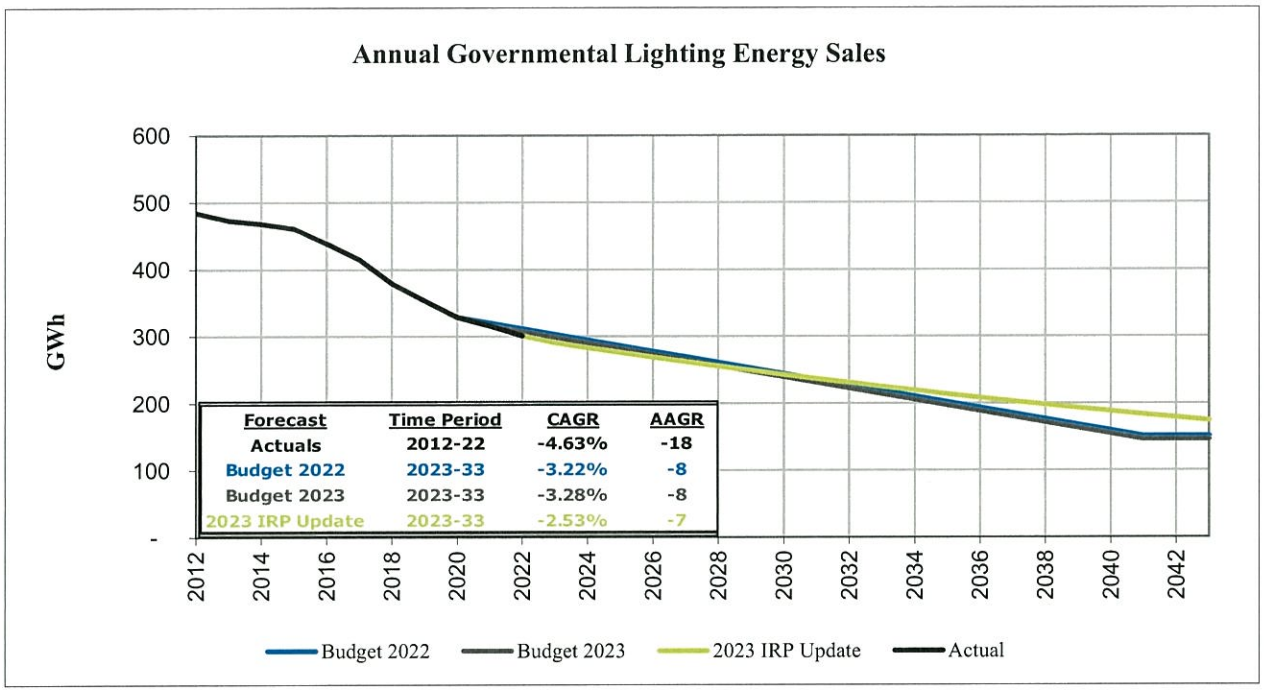
Figure 1.2.4-1: Industrial Energy Forecast



1.2.5 Other Retail: Governmental Lighting, MARTA

Regulated Governmental Lighting and MARTA are Georgia Power's two smallest classes. Combined, they account for about 0.5% of total sales. The regulated governmental lighting forecast is comprised of roadway lighting and traffic control. Governmental lighting sales have declined significantly since 2014 as Georgia Power worked with local municipalities to convert traditional streetlights to LED lights, which use much less energy. Budget 2022 and Budget 2023 recognized that over time traditional streetlights will be replaced with LEDs as they reach the end of their useful lives. The 2023 IRP Update Load Forecast governmental lighting forecast follows a similar trajectory over the forecast horizon for the same reason, as shown in Figure 1.2.5-1.

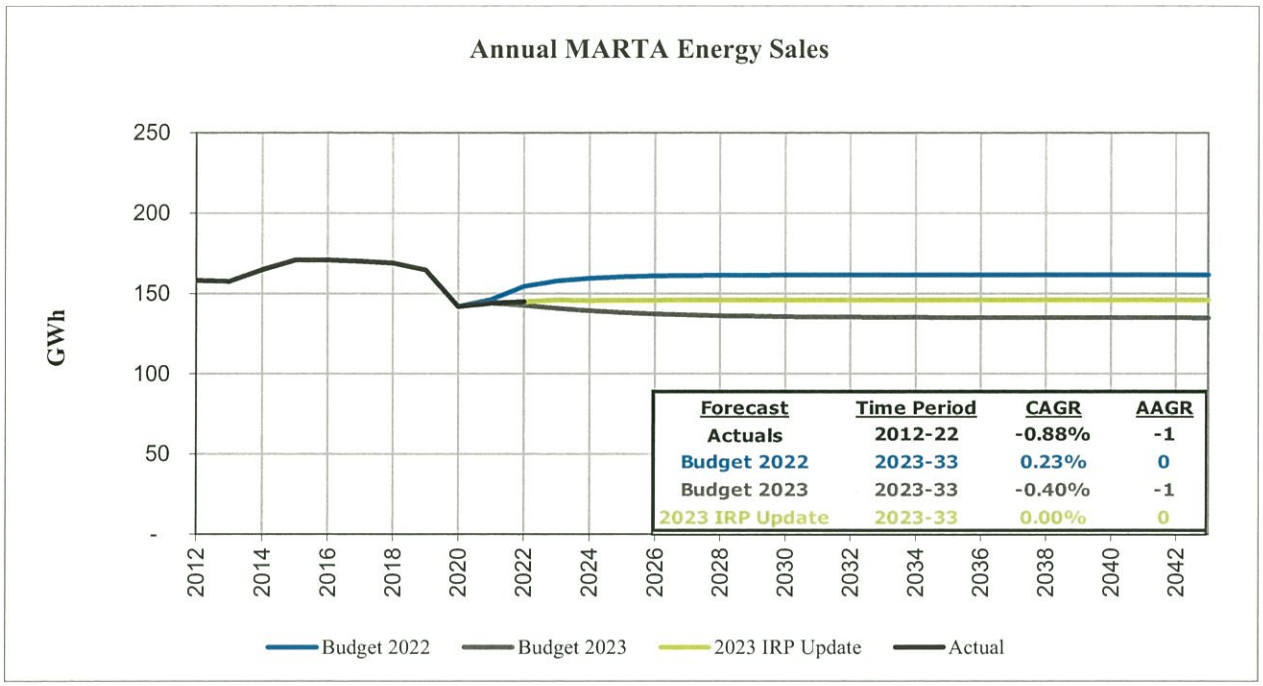
Figure 1.2.5-1: Governmental Lighting Energy Forecast



Forecast	Time Period	CAGR	AAGR
Actuals	2012-22	-4.63%	-18
Budget 2022	2023-33	-3.22%	-8
Budget 2023	2023-33	-3.28%	-8
2023 IRP Update	2023-33	-2.53%	-7

Energy sales to MARTA dropped significantly in 2020 as ridership fell due to the Covid-19 pandemic. As seen in Figure 1.2.5-2, the Budget 2022 MARTA energy forecast assumed that sales would recover, although not to pre-pandemic levels over the forecast horizon. However, actual sales were relatively flat from 2020-2022 as workers travelled to the office less, and worker fears of contracting Covid continued to have a negative impact on MARTA ridership. Energy use is expected to remain at this lower level over the 2023 IRP Update Load Forecast horizon.

Figure 1.2.5-2: MARTA Energy Forecast



1.2.6 Forecast Summary

Figure 1.2.6-1 2023 IRP Update Load Forecast Annual Summary

Year	Retail Sales (GWh)						Territorial Requirements (GWh)	Territorial Supply (GWh)	Summer Peak Demand (MW)	Winter Peak Demand (MW)
	Res.	Com.	Ind.	Gov. Lighting	MARTA	Total Retail				
2023	29,497	32,500	23,341	291	146	85,775	85,775	89,433	16,632	15,371
2024	29,747	32,568	24,181	283	145	86,925	86,925	90,620	16,757	15,283
2025	29,986	35,425	25,846	276	146	91,679	91,679	95,567	17,383	15,947
2026	30,329	43,797	28,232	269	146	102,773	102,773	107,125	18,804	17,256
2027	30,716	55,899	29,849	262	146	116,873	116,873	121,829	20,633	18,928
2028	31,041	62,411	30,581	256	146	124,435	124,435	129,718	21,561	19,751
2029	31,297	68,172	31,211	249	146	131,075	131,075	136,645	22,445	20,551
2030	31,524	73,440	32,536	243	146	137,888	137,888	143,745	23,305	21,326
2031	31,795	75,720	34,761	237	146	142,659	142,659	148,704	23,921	21,880
2032	32,090	76,929	36,084	231	146	145,479	145,479	151,635	24,236	22,141
2033	32,391	77,845	36,385	225	146	146,992	146,992	153,215	24,497	22,353
2034	32,798	78,889	36,644	219	146	148,695	148,695	154,994	24,717	22,515
2035	33,189	79,876	36,876	214	146	150,300	150,300	156,670	24,879	22,630
2036	33,684	81,218	37,118	208	146	152,374	152,374	158,837	25,052	22,746
2037	34,117	82,158	37,354	203	146	153,977	153,977	160,515	25,299	22,938
2038	34,517	83,364	37,585	198	146	155,810	155,810	162,430	25,532	23,257
2039	34,938	84,559	37,784	193	146	157,621	157,621	164,323	25,763	23,624
2040	35,377	85,871	37,997	188	146	159,579	159,579	166,369	25,984	23,926
2041	35,812	86,838	38,204	183	146	161,183	161,183	168,048	26,378	24,282
2042	36,277	87,929	38,426	179	146	162,957	162,957	169,902	26,743	24,643
2043	36,761	89,040	38,612	174	146	164,733	164,733	171,759	27,122	25,033

Figure 1.2.6-2 2023 IRP Update Load Forecast Customer Annual Summary (Year End)

Year	Residential	Commercial	Industrial	Gov. Lighting	MARTA	Total Retail	Total Territorial
2020	2,296,077	318,953	10,701	9,670	1	2,635,402	2,635,402
2021	2,329,283	323,456	10,677	9,509	1	2,672,926	2,672,926
2022	2,366,818	325,805	10,687	9,469	1	2,712,780	2,712,780
2023	2,405,019	328,967	10,683	9,432	1	2,754,102	2,754,102
2024	2,440,229	331,986	10,684	9,452	1	2,792,352	2,792,352
2025	2,472,933	334,882	10,685	9,473	1	2,827,974	2,827,974
2026	2,504,991	337,766	10,686	9,494	1	2,862,938	2,862,938
2027	2,537,332	340,677	10,686	9,515	1	2,898,211	2,898,211
2028	2,569,931	343,607	10,686	9,535	1	2,933,760	2,933,760
2029	2,602,523	346,540	10,686	9,556	1	2,969,306	2,969,306
2030	2,635,062	349,466	10,686	9,577	1	3,004,792	3,004,792
2031	2,667,566	352,390	10,686	9,598	1	3,040,241	3,040,241
2032	2,700,121	355,320	10,686	9,619	1	3,075,747	3,075,747
2033	2,732,713	358,254	10,686	9,640	1	3,111,294	3,111,294
2034	2,765,224	361,187	10,686	9,662	1	3,146,760	3,146,760
2035	2,797,597	364,114	10,686	9,683	1	3,182,081	3,182,081
2036	2,829,964	367,046	10,686	9,704	1	3,217,401	3,217,401
2037	2,862,303	369,981	10,686	9,725	1	3,252,696	3,252,696
2038	2,894,648	372,921	10,686	9,747	1	3,288,003	3,288,003
2039	2,927,017	375,865	10,686	9,768	1	3,323,337	3,323,337
2040	2,959,429	378,815	10,686	9,789	1	3,358,720	3,358,720
2041	2,991,807	381,766	10,686	9,811	1	3,394,071	3,394,071
2042	3,024,138	384,715	10,686	9,832	1	3,429,372	3,429,372
2043	3,056,408	387,661	10,686	9,854	1	3,464,610	3,464,610

1.3 ECONOMICS

Georgia's economy has solidly recovered from the impact of the pandemic and is outpacing the U.S. in terms of employment, unemployment, and Gross Product. Georgia was one of the first 10 states to surpass its pre-pandemic level of total employment. As of August 2023, the state's total number of jobs is 250,000, or 5.3%, higher than before the pandemic. Total U.S. employment, by comparison is up only 2.7% over its pre-pandemic level. Through August, Georgia has added more than 68,000 jobs, up 1.4% since last year, while the U.S. is up 1.2% since last year. Georgia's unemployment rate, at 3.3% in August 2023, remains near its historic low, and is below the U.S. rate of 3.8%.

With respect to real (i.e., inflation adjusted) output since the pandemic, Georgia has grown faster than the overall U.S. economy. As of Q1-2023, Georgia's real Gross State Product was 6.8% higher than its pre-

pandemic peak, compared to 5.6% for the U.S. In Q1-2023, the Georgia economy grew at a 2.4% annual pace compared to a 2% pace for the U.S.

Georgia is benefitting from strong population growth and is currently the eighth most populous state in the nation. Since the 2020 Census, the state has added nearly 201,000 residents, which is the fourth highest increase in the U.S. In terms of percentage growth, Georgia's population has grown 1.9% from 2020-2022 compared to 0.6% growth for the U.S. Net domestic migration accounted for nearly 64% of the population increase since 2020, as the state welcomed over 128,000 residents from other states. This is the seventh highest increase in residents among the 50 states. International migration added over 38,000 residents, while natural growth, calculated as births minus deaths, increased by just over 33,000 from 2020-2022, which is the sixth highest increase in the nation. Robust population growth over the past few years has supported a steady increase in Georgia's labor force, which is essential to continued economic growth.

Georgia's projected employment outlook and favorable living costs will support migration to the state which in turn drives population growth and household formation. In the forecast, Georgia's population is expected to increase an average of 0.8% per year between 2023 and 2043, while the nation's population is expected to increase by 0.4% per year. Increases in Georgia's population, households and business formations are expected to provide a firm foundation for robust long-term economic growth in the state.

1.4 LOAD FORECAST ASSUMPTIONS AND METHODOLOGY

Although the Company introduced a new methodology for forecasting the load of large new customers to account for the state's extraordinary growth, it used the same methodologies employed in the 2022 IRP to prepare its baseline load forecast for the 2023 IRP Update Load Forecast. The underlying baseline forecast was prepared using the economic outlook for the United States and Georgia, energy prices, and market profiles for class end uses. The economic forecast continues to provide a description of the economy for the next 20 years and includes many elements of the economy such as gross product, population, employment, commercial building square footage, and industrial production. The economic and demographic forecasts for the 2023 IRP Update Load Forecast were obtained from S&P Global (formerly IHS Markit), a national provider of economic data and forecasts.

Consistent with the approach taken in the 2022 IRP, the models used to produce the 2023 IRP Update Load Forecast short- and long-term energy forecasts include a variety of economic and demographic variables as drivers of energy use. Weather, income, employment, historical load data, and industry standards for electrical equipment are among the variables used in the forecasting models. "Normal" weather is defined as the average of Cooling Degree Hours ("CDH") and Heating Degree Hours ("HDH") from 1980-2022.

Short-term energy projections for residential, commercial, industrial, governmental lighting, and MARTA are based on linear regression models. Except for governmental lighting and MARTA, the long-term forecast models are end-use models. The 2023 IRP Update Load Forecast uses the Load Management

Analysis and Planning ("LoadMAP") model to produce the long-term residential, commercial, and industrial forecasts. The governmental lighting and MARTA long-term forecasts use the linear regression models developed for the short-term forecast.

The short- and long-term models forecast organic growth based on historical trends, including net customer additions, historic adoption of energy efficiency, the future effect of existing energy efficiency standards, changes in economic conditions and demographics, and trends that develop over time that are part of the Company's historical data, which get propagated throughout the forecast.

The results of the short-term and long-term models are integrated into a unified forecast. In the 2023 IRP Update Load Forecast, the short-term forecast results were used for the years 2023 through 2027 and the long-term results were used for 2028 to 2043. The 2023 IRP Update Load Forecast uses hourly Metrix Peak Demand models ("MPD") for each class to predict Georgia Power's weather-normal peak demands over the 2023 – 2043 forecast period.

1.5 FORECAST ADJUSTMENTS FOR LARGE CUSTOMERS: METHODOLOGY AND ASSUMPTIONS

As mentioned previously, Georgia Power's 2023 IRP Update Load Forecast utilizes a probabilistic approach to evaluate the range and likelihood of future potential outcomes of the load growth from new large customers. The results of this approach support the external adjustment applied to the Commercial and Industrial load and energy forecasts. This section describes the methodology and assumptions behind the probabilistic approach that is used.

In the 2023 IRP Update Load Forecast, the Company made an external adjustment to its baseline forecast to account for the increased large load additions described herein. An external adjustment is needed for these loads since Georgia's unprecedented economic development growth would not otherwise be captured in the historical trends underlying the baseline forecast. Georgia Power has made external adjustments for large new customers in the past. For example, the Company adjusted its forecast in the 2016 and 2019 IRPs to account for the addition of the Elba Island Liquified Natural Gas facility, which represented a completely new industry to the state.

Notwithstanding prior large load external adjustments to the forecast, the Company has never seen such a significant number of new large customer projects materialize in such a short period of time. As a result, Georgia Power has had to develop a way to estimate the impacts of these projects on its system, while also addressing the inherent uncertainties around whether such projects will ultimately locate in Georgia, select Georgia Power as the electric service provider, and come online with the anticipated load. The probabilistic model Georgia Power developed to address these considerations is discussed in the section below.

1.5.1 MODEL OVERVIEW

1.5.1.1 Known Project Inputs

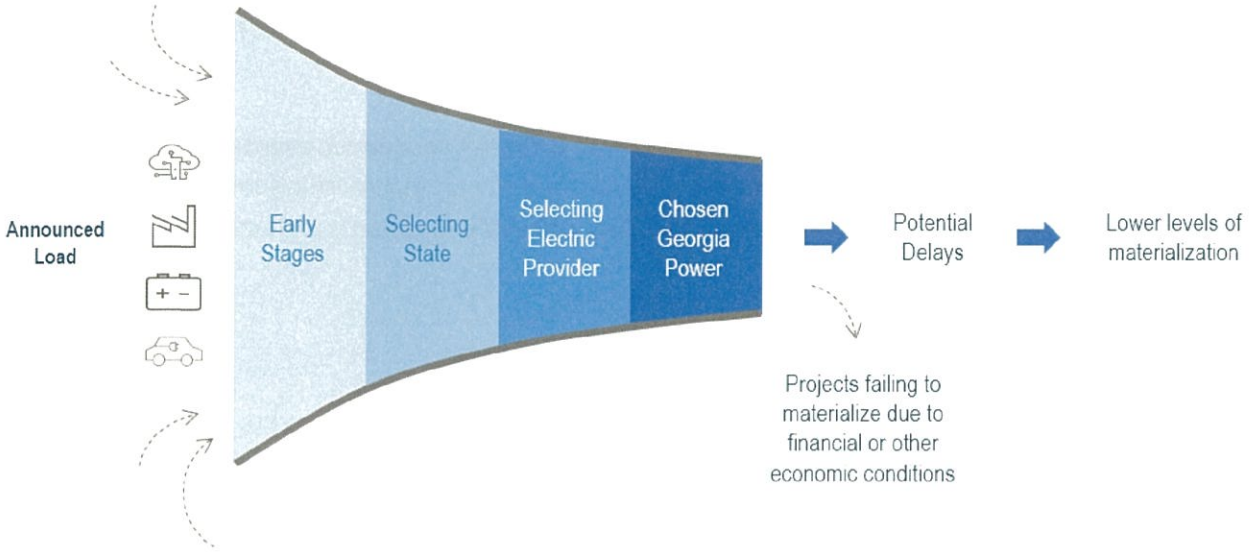
For each large load project the Company has evaluated and included in the 2023 IRP Update Load Forecast, the following information is provided:

- **Commercial Operation Date**: When the initial load is expected to start.
- **Ramp-Up**: A year-by-year load trajectory.
- **Announced Load**: The design capacity for the project load. This corresponds to the maximum load of the ramp-up schedule provided by each customer. The Company's Power Delivery organization uses this information to properly size the facilities and purchase equipment to serve the new load.
- **Class**: Industrial or Commercial.
- **Segment**: This criterion corresponds to the particular segment of a business within a customer class, such as cryptocurrency, datacenter, warehouse, battery manufacturing, chemicals, and solar.

1.5.1.2 Modeling Project Uncertainty

Each large load project contains multiple dimensions of uncertainty that must be considered and analyzed. The first element of uncertainty to consider is whether the potential customers will choose to locate in Georgia. A customer may ultimately end up choosing a different state as the location of a project despite initial indications of interest in Georgia. If a large load customer elects to locate in Georgia, there is still uncertainty due to the competitive nature of the bidding process for large load customers among electric service providers in the state, and a customer may choose an electric service provider other than Georgia Power. There is even some uncertainty once a customer selects Georgia Power as its electric service provider, as the project could fail to materialize due to unforeseen circumstances such as financial or other economic conditions. In addition, based on Georgia Power's experience, the load announced by a customer is only an estimate of its metered load, which can materialize at a lower level than that at the time of the customer's initial announcement. Finally, the commercial operation date of a project can be delayed, thus causing load to materialize later than initially expected. Figure 1.5.1.2-1 below illustrates the Company's process and sequencing for the evaluation of uncertainties related to large load projects.

Figure 1.5.1.2-1: Sequencing of Large Load and Sources of Uncertainty



1.5.1.3 Project Success

The Company uses a probabilistic approach to account for the uncertainties described in the previous section to determine the likelihood of success or failure of an individual project. The success of a project requires each of the following three events:

i. Georgia is chosen as the location of the project.
ii. Georgia Power is chosen as the electric service provider for the project.
iii. The project reaches commercial operation after a contract has been signed with Georgia Power.

1.5.1.4 State Selection

Customers often evaluate sites in multiple states before finalizing the location of a project. Mathematically, state selection can be treated as a binary event, with one (1) assigned for customers that select Georgia and zero (0) for customers that select a different state. For those customers contemplating Georgia as a place for doing business, a probability (referred to as P1) can be assigned for the likelihood of state selection. Likelihood can be estimated based on a historical selection rate that is calculated based on the number of projects that chose Georgia versus the number of projects that did not.

1.5.1.5 Electric Service Provider

Whether a customer chooses Georgia Power as its electric service provider can also be treated as a binary event. The probability of Georgia Power being chosen as the provider (referred to as P2) is determined by the Company based on factors such as competition from other electric service providers, an existing relationship with a customer, and the progress of discussions with a customer.

1.5.1.6 Project Reaching COD

The probability of projects reaching commercial operation (referred to as P3) is determined by reviewing the number of projects that reached commercial operation versus the total number of projects Georgia Power was selected to serve.

For a new large load project to be considered successful, all three of the above events (i.e., state selection, Georgia Power being chosen as electric service provider, and the project reaching commercial operation) must occur. In other words, project success or failure is a binary event that is reflected by the probability formula P=P1*P2*P3.

1.5.1.7 Announced Load vs. Metered Load

To account for the potential difference between the metered load being served, as measured at the customer's meter, versus the load announced by the customer, the ratio (in %) between metered load and announced load is treated as a range. In the absence of actual historical data, the Company identifies minimum and maximum values for this range, as well as a most likely outcome. For example, in the case of data centers, the range is between REDACTED% and REDACTED% of the customer's announced load, with a most likely outcome of REDACTED%. Mathematically, this is modeled with a triangular distribution (see Section 1.5.3 for more technical details).

Table 1.5.1.7-1 below demonstrates the parameter inputs for modeling the metered load compared to the announced load, based on the customer class and segment.

Table 1.5.1.7-1: Specifications of Triangular Distributions for Metered vs. Announced

Class	*Segment*	*Low*	*Mid*	*High*
Commercial	Cryptocurrency	**REDACTED**	**REDACTED**	**REDACTED**
	Datacenter	**REDACTED**	**REDACTED**	**REDACTED**
	Miscellaneous	**REDACTED**	**REDACTED**	**REDACTED**
	Warehouse	**REDACTED**	**REDACTED**	**REDACTED**
	Distribution	**REDACTED**	**REDACTED**	**REDACTED**
Industrial	All Segments	**REDACTED**	**REDACTED**	**REDACTED**

1.5.1.8 Commercial Operations Date Delay

Projects often experience delays in their commercial operation date. The expected delays are shown in Table 1.5.1.8-1 and can range between **REDACTED REDACTED REDACTED REDACTED REDACTED**. The parameter inputs for modeling the probability of delays in commercial operation are based on the Company's estimates.

Table 1.5.1.8-1: Specifications of Triangular Distributions for Delay

Class	*Segment*	*Low*	*Mid*	*High*
Commercial	All segments	**REDACTED**	**REDACTED**	**REDACTED**
Industrial	All Segments	**REDACTED**	**REDACTED**	**REDACTED**

1.5.2 MODELING THE PORTFOLIO

The portfolio of large load projects being assessed by the Company consists of projects in numerous phases of development, ranging from early stages, such as the state selection or site selection phases, to those under construction and projected to be served by the Company. This creates multiple dimensions of uncertainty for each project that requires a Monte Carlo simulation model to quantify a range of expected load to serve.

Monte Carlo simulation is a mathematical technique that is used to estimate the possible outcomes of a portfolio with uncertain events. Unlike a normal forecasting model, Monte Carlo simulation predicts a set of outcomes based on an estimated range of values versus a set of fixed input values. The simulation assigns random values to input variables with uncertainty based on probability distributions such as triangular distributions mentioned in Section 1.5.1.7 and calculates an outcome. It then repeats the process over and over (at least thousands of times typically), each time using a different set of random inputs, to produce a large number of outcomes.

1.5.2.1 Model Implementation

The model described in this appendix is implemented in Excel with a third-party add-in called @Risk. @Risk allows incorporating probability distributions into an Excel spreadsheet so that Monte Carlo simulation and analysis can be done to track the range of potential outcomes and calculate a wide array of statistics (average, standard deviation, percentiles, etc.).

For each project in the model, there are three random numbers being drawn for success/failure, metered/announced ratio, and delay in COD from the distributions described in Section 1.5.1. For a particular draw, if the success/failure random number is 0, or failure, the load of the project is 0 and the project is excluded from the portfolio. If the success/failure random number is 1, or success, the announced load ramp-up gets scaled by the metered/announced ratio random number and then shifted according to the timing of the ramp-up by the number of months determined by the delay in COD random number. Finally, this adjusted and shifted ramp-up is aggregated year by year into the portfolio level.

1.5.2.2 Simulation Results

The procedure described in section 1.5.2.1 is repeated 100,000 times. Then, these 100,000 load iterations get ranked for each year in order to calculate load percentiles, which helps the Company to understand the load range and compare the likelihood of load outcomes for the portfolio. The table below shows the

external adjustments included in the 2023 IRP Update Load Forecast, which are consistent with the 95th percentile of simulated load.

Table 1.5.2.3-1 2023 IRP Update Load Forecast External Adjustments

Year	*Load (MW)*
2023	**REDACTED**
2024	**REDACTED**
2025	**REDACTED**
2026	**REDACTED**
2027	**REDACTED**
2028	**REDACTED**
2029	**REDACTED**
2030	**REDACTED**
2031	**REDACTED**
2032	**REDACTED**
2033	**REDACTED**
2034	**REDACTED**
2035	**REDACTED**
2036	**REDACTED**
2037	**REDACTED**
2038	**REDACTED**
2039	**REDACTED**
2040	**REDACTED**
2041	**REDACTED**
2042	**REDACTED**

1.5.3 TRIANGULAR DISTRIBUTION

The triangular distribution is a continuous probability distribution with the following parameters:

a: $a \in (-\infty, \infty)$

b: $a < b$

c: $a \leq c \leq b$

In the case of metered versus announced uncertainty, *a* represents the minimum metered/announced ratio, *b* represents maximum metered/announced ratio and *c* represents the most likely metered/announced ratio.

Figure 1.5.3-1: Probability Density Function for a Triangular Distribution

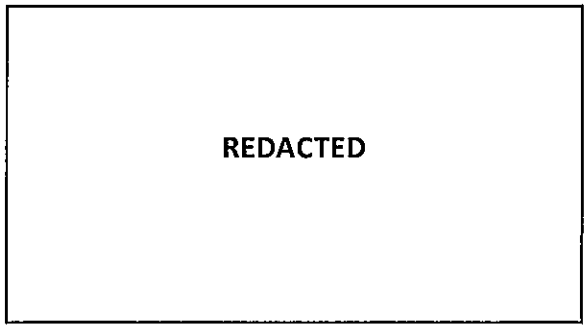
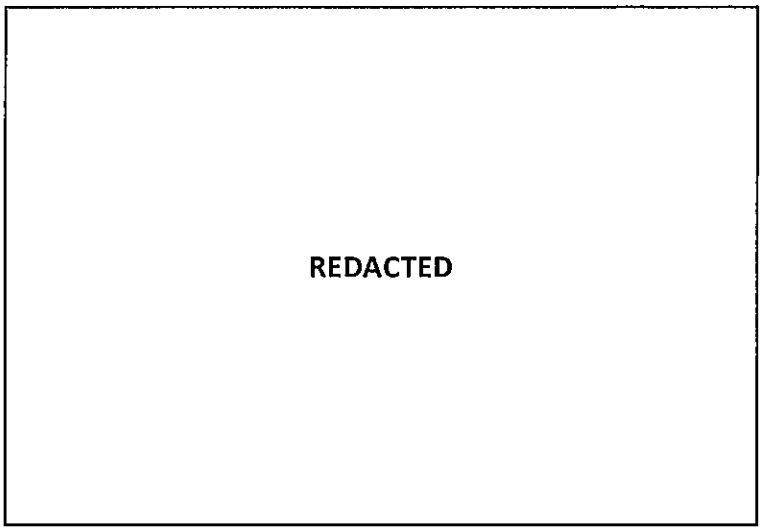


Figure 1.5.3-2: Probability Density Function of Triangular Distribution with a= REDACTED%, c=REDACTED% and b=REDACTED%



Triangular distributions are chosen for this model for the following reasons:

- A triangular distribution has a finite range while other commonly used probability distributions such as normal and lognormal distributions have an infinite range and can even be negative, which is inappropriate to depict the actual/announced ratio.
- The min/max/most likely parametric setup of triangular distributions is intuitive and straightforward to interpret. In contrast, the parameters of some other commonly used distributions are somewhat opaque. For example, normal distributions are defined in terms of mean and standard deviation. Additional calculation is needed to translate those into the range of outcomes that are more appropriate for the context of actual vs. announced load.
- Other than the standard min/max/most likely parametric setup, triangular distributions can also be defined by a combination of percentiles, min, max and most likely, which offers more flexibility to fine-tune the model.

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Southern Company

2023 Integrated Resource Plan Update

Resource Mix Study

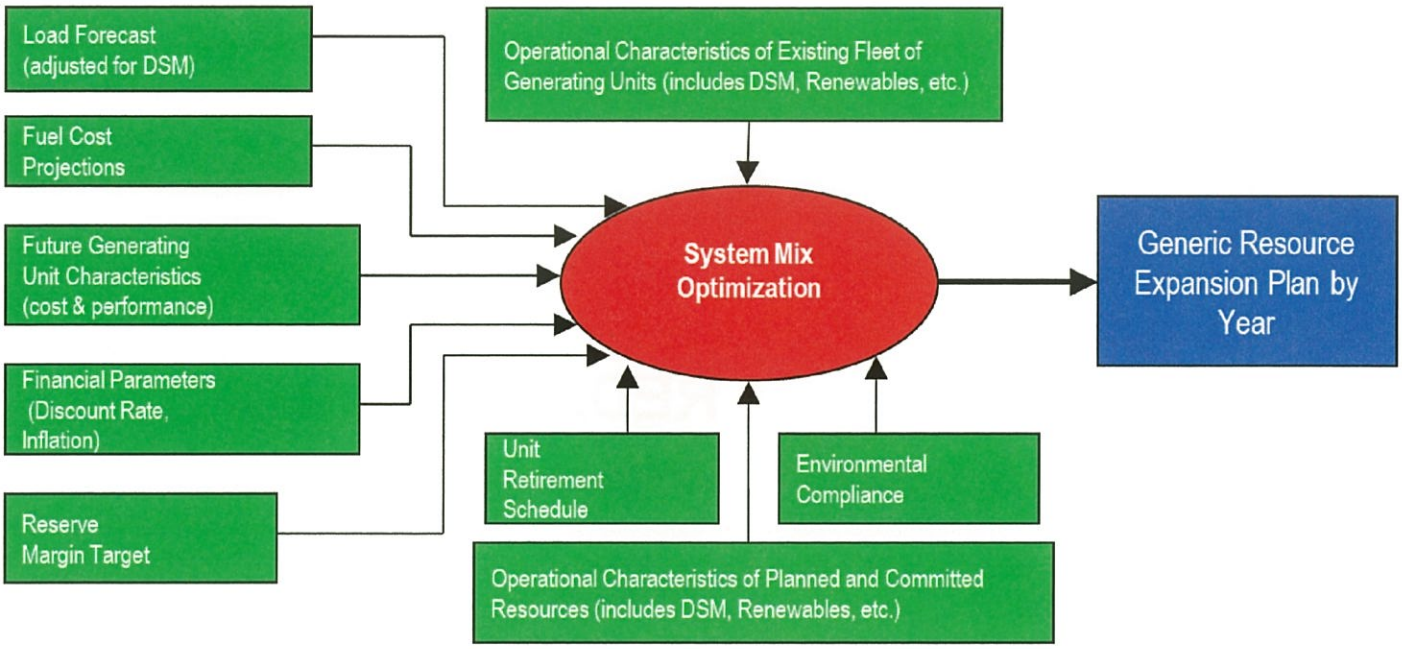
October 2023

1 SUMMARY

The primary objective of this study is to provide information regarding the development of an optimal least-cost resource mix or generic expansion plan. The generic expansion plan was selected to minimize revenue requirements while complying with reliability criteria, environmental laws, and regulations, considering risk and flexibility. This study provides an informative roadmap for long-term decisions. The base case contained in this Mix Study does not represent commitments but instead is a generic expansion plan used for planning and to support analyses. Under the framework established in the state of Georgia, when a capacity need is identified through an Integrated Resource Plan ("IRP"), Georgia Power Company ("Georgia Power" or the "Company") will meet such identified need in accordance with the Georgia Public Service Commission ("Commission") rules and will utilize Georgia Power specific information, as appropriate.

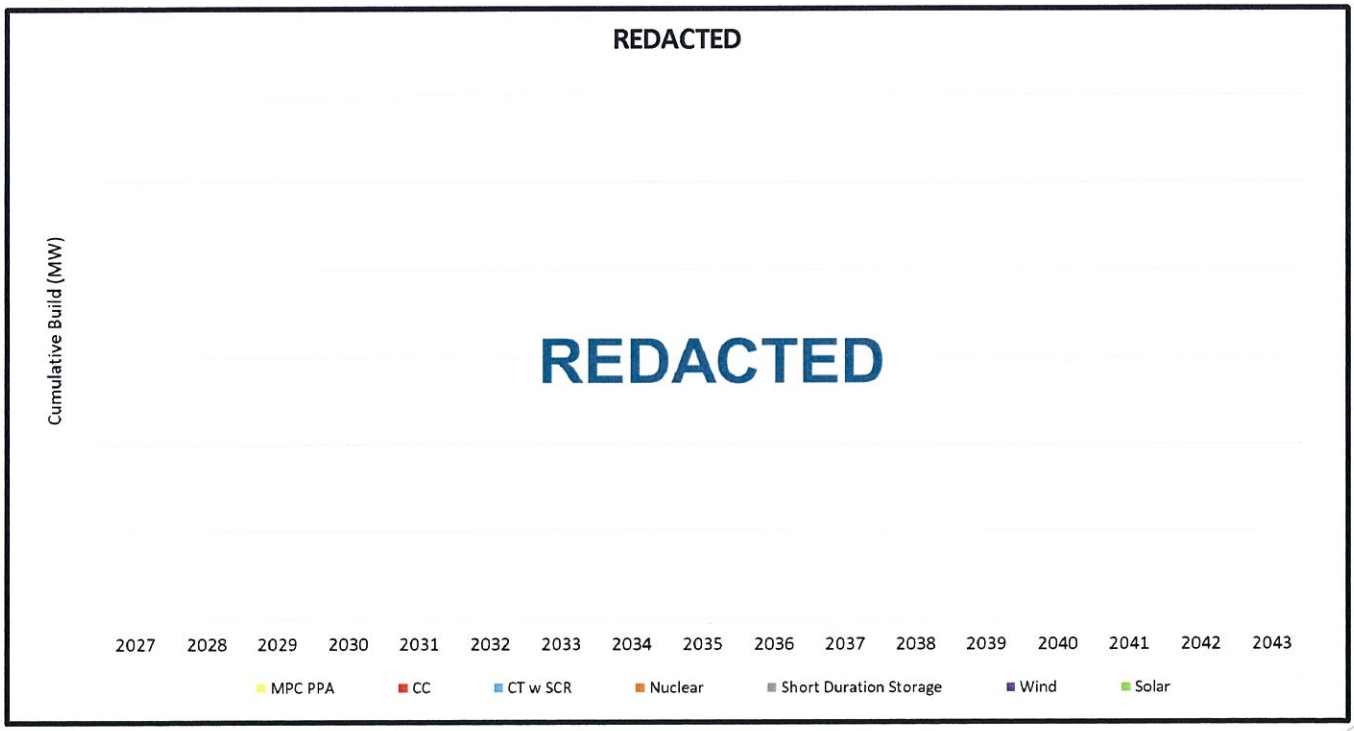
This report summarizes the results of the 2023 IRP Update Resource Mix Study. The recommendations of the study provide input to an optimum resource addition schedule for the retail operating companies. The base case resource addition schedule is based on maintaining minimum winter and summer reserve margins and minimizing the total operating and capital costs over the planning horizon. While both summer and winter seasons are reviewed, future resource addition schedules will be based on the additions needed to meet the higher of the summer or winter capacity need. For this 2023 IRP Update resource plan, the winter capacity need occurred earlier and was higher than the summer capacity need for the entire planning horizon. Therefore, the system expansion plan includes additions to address the forecasted winter capacity needs. An overview of the expansion plan optimization process is shown in Figure 1 below.

Figure 1: Expansion Plan Optimization Process Overview



In developing a resource expansion plan, it is important to consider uncertainties that could impact planning decisions. Key uncertainties affecting planning include the evolution of natural gas prices, future environmental pressure—especially regarding carbon-dioxide ("CO_2"), cost and performance of future generating technologies, and future load growth. Therefore, in developing its scenarios, the Company identifies different plausible viewpoints in each of these four areas. These viewpoints are combined to create six scenarios for the 2023 IRP Update. For purposes of this resource mix study, a single scenario is available upon the 2023 IRP Update filing date. However, Georgia Power will file the additional five scenarios in a supplemental filing in the 2023 IRP Update docket. Shown in Figure 2 is the generic capacity expansion plan (cumulative megawatts ("MW") by 2043) for the moderate gas, zero-dollar carbon ("MG0") scenario.

Figure 2: 2023 IRP Update MG0 Expansion Plan – Cumulative MW by 2043



2 ASSUMPTIONS

The key inputs to the study are the cost of capital and escalation rates, a reliability criterion represented by the Target Reserve Margin, the operating data and retirement or projected unavailability dates of existing and committed generating units, projected demand side options ("DSOs"), load forecasts, fuel forecasts, and costs and performance characteristics of candidate generating technologies. The following provides details for each of these key inputs.

2.1 FINANCIAL ASSUMPTIONS

Cost of capital rates are based on the Markit June 2023 forecast. Table 1 details the capital structure and weighted costs used in the Mix Study.

Table 1: Capital Structure

Component	Ratio	Cost	Weighted	After Tax Hurdle Rate	Revenue Requirement Rate
Debt	45%	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**
Equity	55%	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**
Weighted Cost			**REDACTED**	**REDACTED**	**REDACTED**

2.2 RESERVE MARGIN

The 2023 IRP Update reflects a 16.25% Summer Target Reserve Margin and 26% Winter Target Reserve Margin for long-term resource planning purposes, consistent with the Commission's final order in GPC's 2022 IRP.

2.3 EXISTING CAPACITY MIX

The Company's current generating capacity consists of 18% coal, 48% gas and oil, 11% nuclear, 5% hydro, and 18% other[1] (Solar, Solar + Storage, Wind, DSO, and Biomass). Over the course of the planning horizon, the capacity mix will change due to many factors, including, but not limited to, unit rating changes, resource additions, nuclear license expirations, power purchase agreement expirations, and retirements. For planning purposes, discrete retirement dates of Company-owned generating units were utilized in the base case. Please refer to Technical Appendix Resource Mix Study (Georgia Power Territorial Base Case Load vs. Existing Capability Table) for more details.

2.3.1 DEMAND-SIDE OPTIONS

Demand-side options are either "dispatchable" or "non-dispatchable." Examples of dispatchable DSO include interruptible load and other options that can be controlled and dispatched by a utility. Examples of non-dispatchable DSO include options such as insulation or end-use equipment efficiency, which are not directly controllable by a utility.

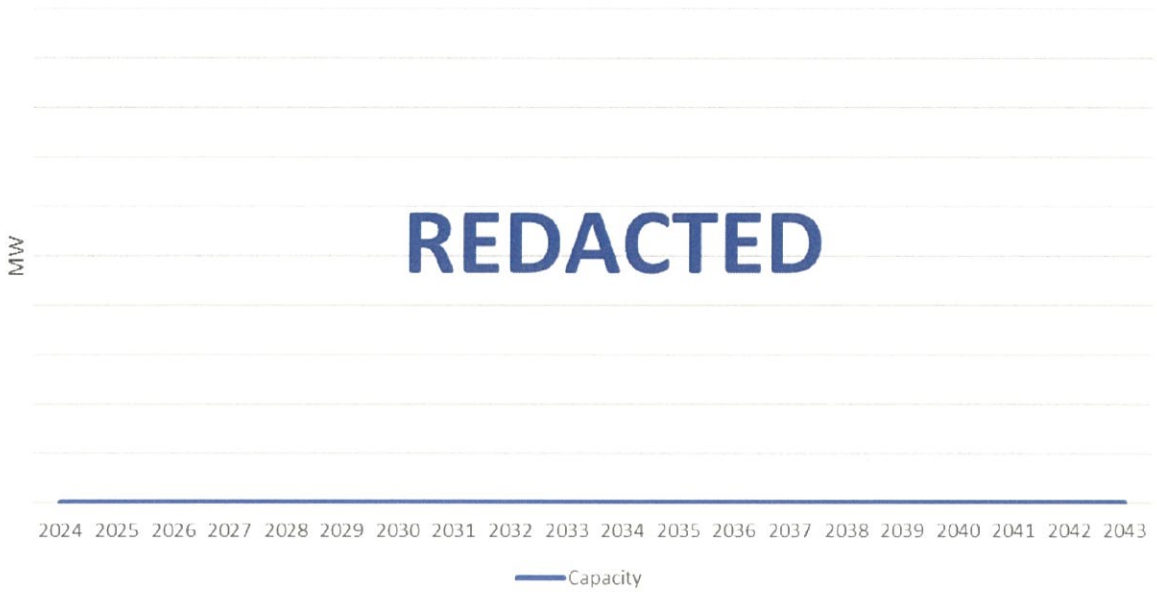
Dispatchable DSOs were included as capacity resources in this study. Each interruptible contract load was appropriately adjusted to equate it to the supply side by one or more of the following corresponding factors: availability factor, loss factor, and Effective Load Carrying Capability ("ELCC"). For all operating companies, non-dispatchable DSOs are accounted for in the load forecast. Please see Technical Appendix Resource Mix Study (Georgia Power and System DSO Data) for additional information regarding DSO assumptions used in the 2023 IRP Update.

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[1] A portion of the renewable nameplate generation capacity included in this value includes capacity where the renewable generator retains the related Renewable Energy Credits ("RECs").

Figure 3 below shows the existing, planned, and committed system capacity changes for the 2024 – 2043 period.

Figure 3: Retail Operating Companies' Existing and Planned Capacity Forecast



2.4 LOADS

Load forecasts were provided by each retail operating company. The System peak demand is the sum of each retail operating companies' non-coincident peak demand multiplied by a load diversity factor. The diversity percentages are based on a historical ten-year average of monthly diversities from 2013 through 2022. More information on the Company's load forecasts can be found in the 2023 IRP Update Main Document and the Load and Energy Forecast presented in the Technical Appendix.

To address the uncertainty of future electricity consumption across a range of scenarios, the Company produces specific load forecasts for multiple scenario views. The Company's reference load forecast uses annually updated forecasts of electricity consumption throughout the planning horizon assuming the US Energy Information Administration's ("EIA") 2023 Annual Energy Outlook ("AEO") "Reference" gas price forecast and a $0 carbon view. The forecast is done separately for each of the three types of customers—residential, commercial, and industrial. For each scenario, this reference load forecast is adjusted to include the impacts of the changing fuel or carbon forecast used in that scenario.

The state of Georgia has seen historic growth in economic development activity, specifically new load related to data centers, clean energy technology, and manufacturing. Due to the speed in which economic development customers are growing, the Company has produced a load scenario that captures the increased speed and magnitude in which these customers are growing. This load scenario ("2023 IRP Update Load Forecast") is specific to the 2023 IRP Update and will be used as the reference load forecast in this Mix Study. Additionally, the Company produces two other load forecast views used in the scenarios that include additional electrification-influenced load growth and end-use efficiency and customer generation with varying degrees of added carbon pressure ("Alt 1" and "Alt 2").

- Alt 1 Load Forecast: The Alt 1 load view reflects the Company's view of how a moderate amount of CO_2 pressure would have two generally opposing effects on load growth. First, CO_2 pressure would be consistent with increased electrification of transportation, thus increasing load growth. Second, CO_2 pressure would be consistent with increased efficiency of electricity end-use either because of improved energy efficiency of devices or because of income and substitution effects associated with more expensive electricity, which would have the effect of reducing load growth.
- Alt 2 Load Forecast: The Alt 2 load view reflects a similar forecast to Alt 1, except that it reflects the effects of a large degree of CO_2 pressure, rather than a moderate degree.

Additional scenario analyses, including those based on the Alt 1 and Alt 2 load forecasts, will be provided in a supplemental update.

2.5 FUEL FORECASTS

Near term base fuel costs are based on the Southern Company fuel budgeting process. For the 2023 IRP Update, the Company adopted and adapted paths produced by EIA for its 2023 AEO for the long-term fuel costs. The following illustrations give the fuel price paths that the Company has used in the 2023 IRP Update scenario analysis. Only the moderate fuel price views are used for the Mix Study, but additional analyses including the other fuel price views will be provided in a supplemental update.

Figure 4: Views of future price of Natural Gas at Henry Hub

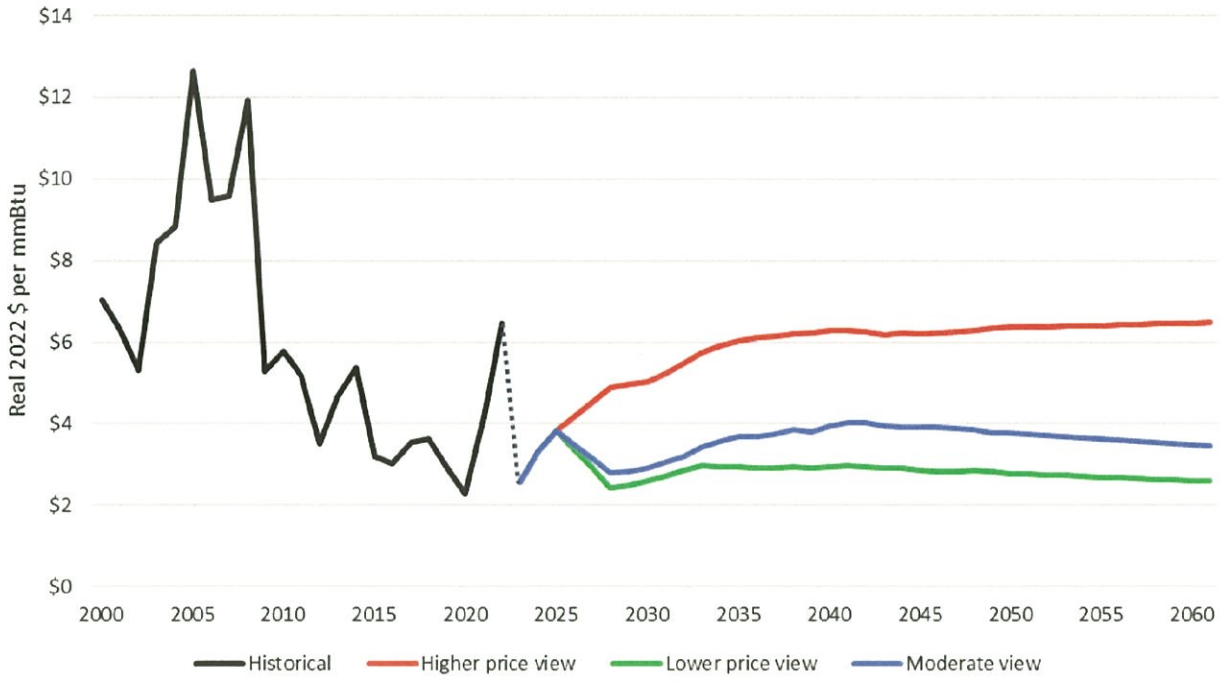


Figure 5: Views of future price of coal at mine, by scenario, Central Appalachia

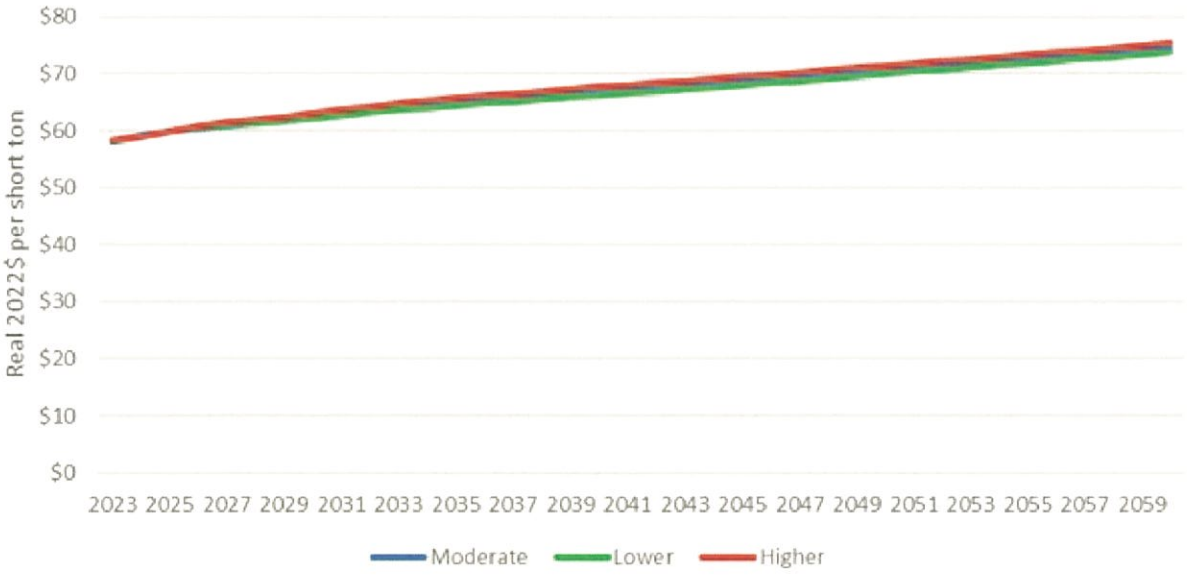


Figure 6: Views of future price of coal at mine, by scenario, Illinois Basin

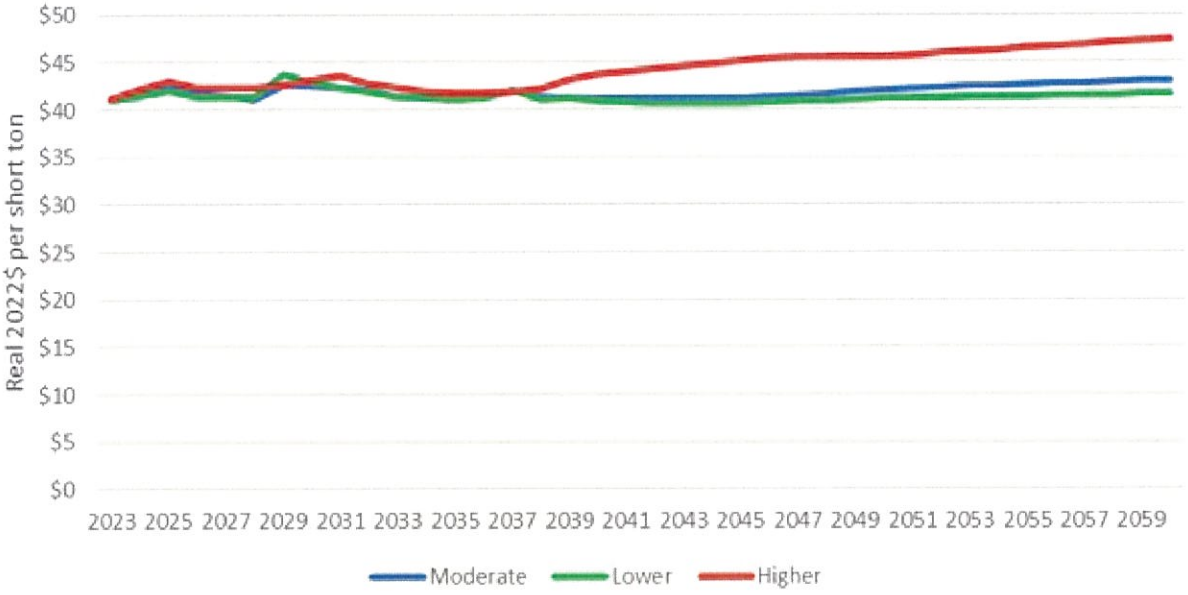


Figure 7: Views of future price of coal at mine, by scenario, Powder River Basin

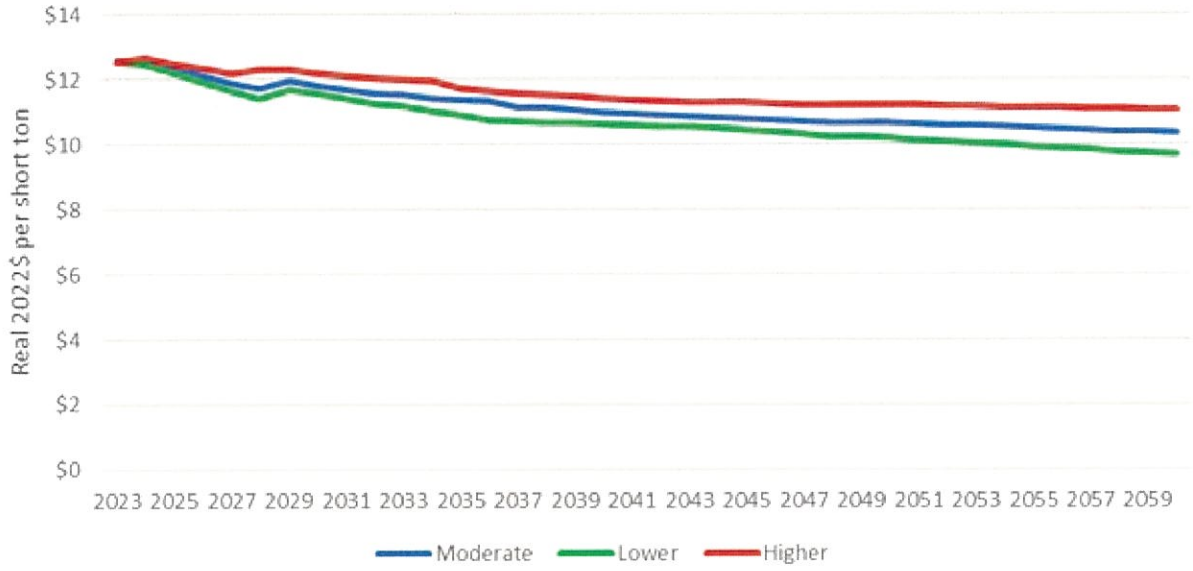
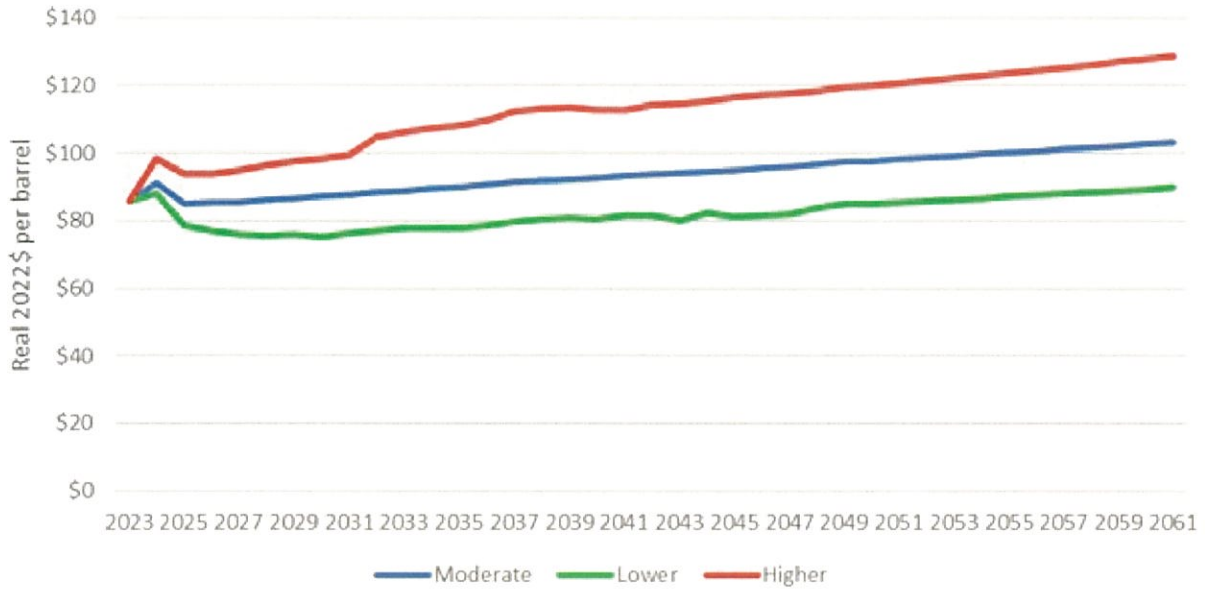


Figure 8: Views of future price of oil, West Texas Intermediate



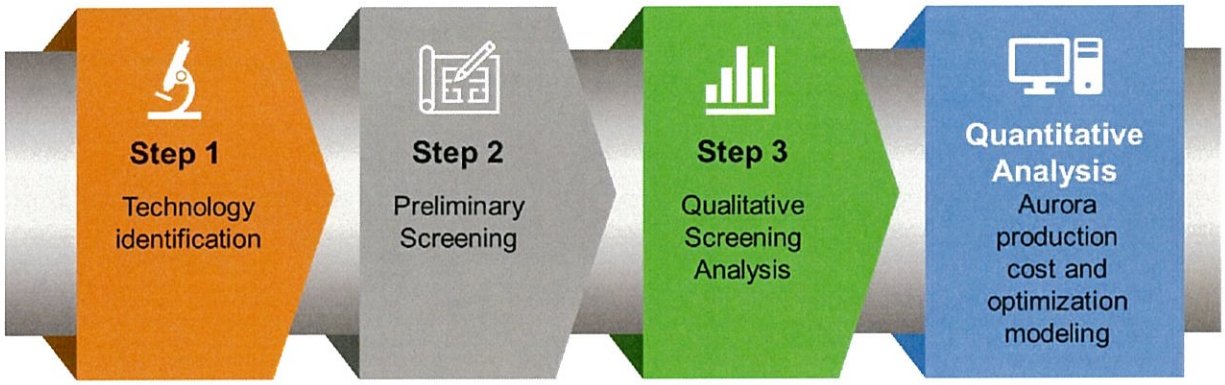
The candidate expansion unit gas price is a capacity need weighted average, by retail operating company, of several potential plant locations throughout the Southern Company System. Combined cycle additions include the cost of contracting for firm annual natural gas delivery, and combustion turbine additions include the cost of contracting for firm summer only natural gas delivery.

2.6 TECHNOLOGY SCREENING & CANDIDATE EXPANSION UNITS

The Company performs detailed expansion planning and production cost analysis during each IRP. This detailed analysis requires extensive and complex computational analysis. Therefore, the Company completes a technology screening assessment of new generation technologies to reduce the potential list of new supply-side options to a manageable list of technologies that are likely to be economically competitive. This technology screening assessment evaluates both established and emerging generating technologies. The objective is to assess the cost, maturity, safety, operational reliability, flexibility, economic viability, environmental acceptability, fuel availability, construction lead times, and other relevant factors of new supply-side generation options.

The technology screening process includes three main steps: (i) the Technology Identification, (ii) Preliminary Screening, and (iii) Detailed Qualitative Screening Analysis, as illustrated in Figure 9. Supply-side options retained after these steps are then considered in the more detailed expansion plan modeling.

Figure 9: Technology Screening Process



The screening process is useful for comparing costs of resource types but cannot be solely utilized for determining a long-term resource plan because future units must be optimized with an existing system containing various resource types. Results from the screening analysis provide guidance for the technologies to be further considered in the more detailed quantitative analysis phase of the planning process. All resources that passed Steps 1-3 of the technology screening process were offered to the model to be optimized with the existing system.

2.6.1 CANDIDATE EXPANSION UNITS

For 2023 IRP Update analyses, the technologies that screened as potentially cost-effective included natural gas combined cycle (with and without carbon capture and sequestration), dual-fuel combustion turbine with Selective Catalytic Reduction ("SCR"), reciprocating internal combustion engine, solar photovoltaic, wind, advanced nuclear, and battery storage (short- and medium-duration).

- **Natural Gas Combined Cycle ("CC" and "CC with CCS")**: The Company's current assumption for planning purposes is that CC plants without carbon capture facilities are available for fleet expansion beginning in 2030 and only through 2039 ($0 CO_2 view) or 2034 (all other CO_2 views). This is due to a corresponding planning assumption that beginning in 2035 or 2040, depending on the CO_2 view, new CC plants must capture at least 90% of their carbon dioxide emissions. The timing of this requirement is based on the Company's understanding of the existing Clean Air Act and its statutory requirements for review of abatement technologies (New Source Performance

Standards and Best Available Control Technology). With a carbon capture facility, CC plants are referred to as natural gas combined cycle with carbon capture and storage ("CC with CCS"). The Company assumes that CC with CCS that is online by end of 2038 will receive the 12-year 45Q tax credit for each ton of carbon that is captured and stored.

- **Dual-Fuel Combustion Turbines ("CT with SCR")**: The Company's current assumption for planning purposes is that dual-fuel combustion turbines with SCR are available for fleet expansion beginning in the year of capacity need for each scenario and assumed to operate with oil as a primary fuel source. CTs must significantly reduce their NO_x emissions by installing an SCR device. This assumption comes from recent deployments of this technology across the industry and the Company's understanding of the existing Clean Air Act and its statutory requirements for review of abatement technologies and requirements.

- **Reciprocating Internal Combustion Engine ("RICE")**: Reciprocating internal combustion engines are available as an expansion resource beginning in the year of capacity need for each scenario.

- **Solar PV**: Solar PV with single-axis tracking is available as an expansion resource beginning in 2027. The Company's view is that its costs will continue to decline in real terms, meaning it will become increasingly cost-effective throughout the study timeframe. The Company assumes that solar will receive the 10-year clean electricity production tax credit as part of the Inflation Reduction Act ("IRA").

- **Southeast Wind**: Wind is available as an expansion resource beginning in 2032. The Company assumes that wind will receive the 10-year clean electricity production tax credit as part of the IRA. Wind has been limited to 8,100 MW total within the Southern Company footprint based on expected wind resource potential and land availability.

- **Battery energy storage systems ("BESS")**: Battery storage (4-hour option) is available as an expansion resource beginning in the year of capacity need for each scenario. The Company's view is that its costs will continue to decline into the middle of the planning horizon, before leveling off in real terms, meaning that it will become increasingly cost-effective throughout the study timeframe. The Company assumes that battery storage is able to take advantage of a 40% investment tax credit as part of the IRA.

- **Medium duration energy storage systems ("MDESS")**: MDESS (12-hour option) is available as an expansion resource beginning in 2033. MDESS is assumed to be representative of pumped thermal energy storage. The Company assumes that MDESS is able to take advantage of a 40% investment tax credit as part of the IRA.

- **Nuclear**: Advanced nuclear options including Small Modular Reactors and Generation IV Nuclear technology are considered as part of the technology screening. Small Modular Reactor cost and performance metrics are modeled and available as an expansion resource. The Company assumes that nuclear will receive the 10-year clean electricity production tax credit as part of the IRA.

- **Power Purchase Agreement between Georgia Power Company and Mississippi Power Company**: Due to the significant increase in economic development load that the Company has seen, the Company's first capacity need falls in Winter of 2027. Many of the technology options are not assumed to be available as early as Winter 2027. Because of this, for planning purposes, the

Company has included the Georgia Power Company and Mississippi Power Company PPA as a resource option within the model. It is modeled to assume the capacity and energy costs per the executed PPA in the Technical Appendix to the 2023 IRP Update.

2.6.2 GENERIC UNIT COSTS AND PERFORMANCE

Table 2 shows the technology assumptions for the candidate units offered in the 2023 IRP Update Mix Study.

Table 2: Candidate Technology Assumptions

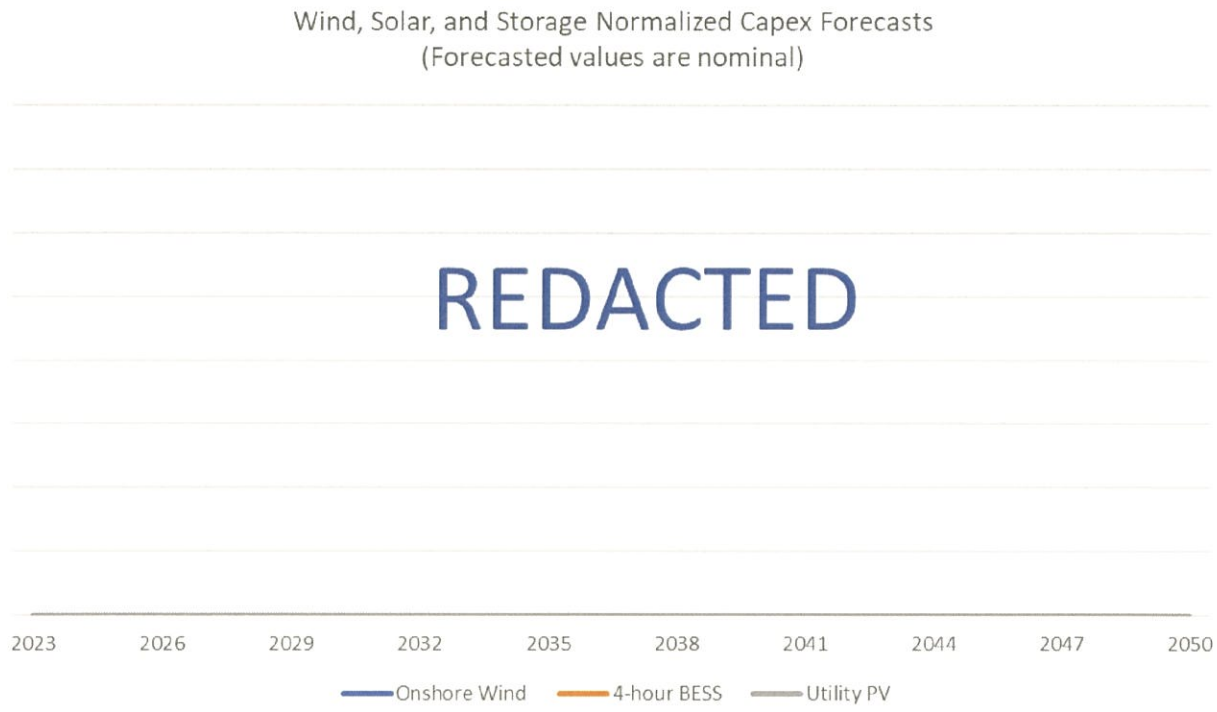
Technology	Capacity Winter (MW)	ICE Factor	Average Heat Rate (Btu/ kWh)	Round Trip Efficiency	Fixed Capacity Factor	Overnight Cost (2023$/ kW)	Recurring Fixed Cost[2] (2023$/ kW-yr)	Variable O&M ($/MWh)	Asset Life (Yrs)
Combined Cycle (CC)	REDACTED	REDACTED	REDACTED			REDACTED	REDACTED	REDACTED	REDACTED
Combined Cycle with Carbon Capture & Storage (CC w CCS)	REDACTED	REDACTED	REDACTED			REDACTED	REDACTED	REDACTED	REDACTED
Combustion Turbine with Future Emission Controls (CT w SCR)	REDACTED	REDACTED	REDACTED			REDACTED	REDACTED	REDACTED	REDACTED
Reciprocating Internal Combustion Engines (RICE)	REDACTED	REDACTED	REDACTED			REDACTED	REDACTED	REDACTED	REDACTED
Solar Photovoltaic (PV) - Single Axis Tracker (SAT)	REDACTED	REDACTED			REDACTED	REDACTED	REDACTED		REDACTED
Onshore Wind Power	REDACTED	REDACTED			REDACTED	REDACTED	REDACTED		REDACTED
Lithium-ion Battery Energy Storage System (BESS) - 4 Hr	REDACTED REDACTED	REDACTED REDACTED REDACTED REDACTED		REDACTED		REDACTED	REDACTED	REDACTED	REDACTED
Medium Duration Energy Storage System	REDACTED REDACTED	REDACTED		REDACTED		REDACTED	REDACTED	REDACTED	REDACTED
Small Modular Reactors (SMRs)	REDACTED	REDACTED				REDACTED	REDACTED		REDACTED

[2] Recurring fixed costs includes Fixed O&M, Maintenance Capital, and Natural Gas Firm Transportation.

Construction cost escalation rates for all technologies except solar, wind, and BESS are based on the Producer Price Index ("PPI") from the IHS Markit June 2023 Forecast, which is REDACTED% for the duration of the planning period.

Figure 10 shows the normalized cost projections for Southeast Wind, Solar, and BESS, which show the escalation trajectory used in the Resource Mix study.

Figure 10: Normalized Cost Projections for Southeast Wind, Solar, and BESS



Aurora selects new units based on minimizing total operating and capital costs. In order to minimize potential size bias, a unit size of 300 MW was considered for all technologies. The model adds resources in multiples of 300 MW.

2.6.3 INFLATION REDUCTION ACT

The IRA was passed in August of 2022, providing tax incentives to various clean energy technology options. These tax incentives have been incorporated into various technology options that are eligible for selection

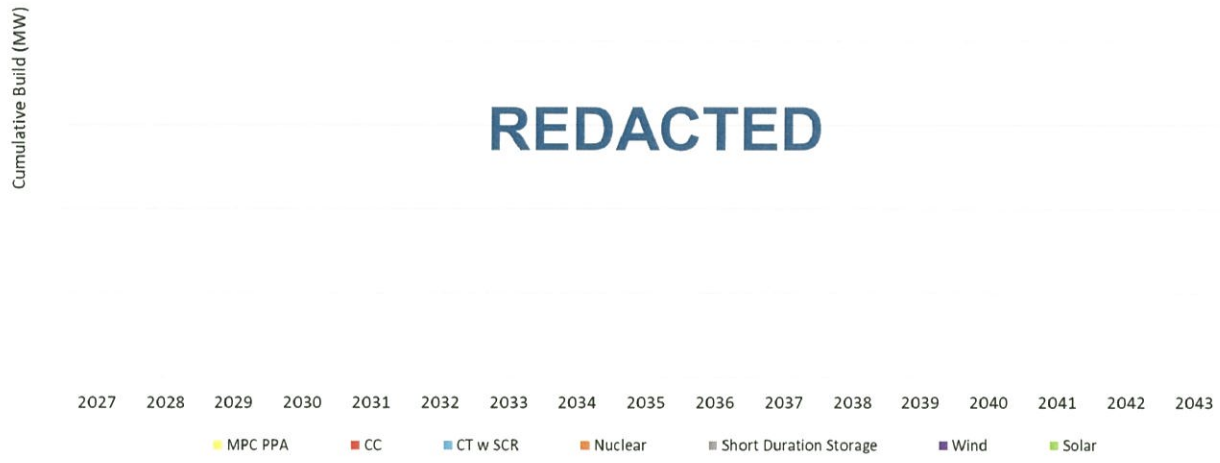
in the Mix Study. Section 2.6.1 on the candidate expansion technologies references how the IRA credits are incorporated for each eligible technology.

The IRA has various provisions for when incentives are set to end. Many tax credits are set to phase out at the later of 2032 or when the nation-wide electric sector reaches 75% carbon emission reduction from 2022 levels. Due to the progression of current carbon emission reductions, the IRA incentives are assumed to extend through the planning horizon for all \$0 CO_2 scenarios. For CO_2 scenarios, the IRA incentives are assumed to phase out earlier, due to the additional greenhouse gas pressure. The phase out is assumed to begin in 2045 for the \$20 CO_2 view and in 2035 for the \$50 CO_2 view.

3 BASE CASE GENERIC EXPANSION PLAN

The following base case capacity addition schedule was used as an input to the integrated resource planning process for the retail operating companies. The base case scenario reflects the moderate gas, zero-dollar carbon ("MG0") scenario. Figure 11 below shows the recommended capacity and energy addition schedule for generic expansion.

Figure 11: 2023 IRP Update MG0 Expansion Plan



The conclusion of this study, based upon the results of the base case, is that additional generation capacity requirements may involve a mixture of natural gas combined cycle, dual-fuel combustion turbine with SCR, advanced nuclear, solar photovoltaic, wind, and battery storage. Additionally, the study concludes that a market option, such as the Mississippi Power Company PPA, will be needed to meet near term capacity needs. At the appropriate time, actual resource selection will occur in accordance with Commission rules. Additional conclusions will be drawn upon completion of all scenarios and sensitivities to be filed in the supplemental update.

Please see Technical Appendix Resource Mix Study (GPC and System IRP Summary Data) for additional summary information regarding the Georgia Power and System capacity, peak demands and energies, actual and target reserve margins, and capacity needs.

4 SCENARIO ANALYSIS AND DISCUSSION OF RESULTS

4.1 PLANNING SCENARIO CASES

Due to the uncertainty related to long term fuel cost, carbon pressure, technology cost and performance, and future electricity consumption, the Company considers multiple views of the future price of natural gas, multiple views of future pressure on the Company's CO_2 emissions, multiple views of future cost and performance of generating technologies, and multiple views of future electricity consumption. For the 2023 IRP Update, the Company assembled these multiple views in those four areas into six planning scenario cases to explore the potential impacts. This resulted in six outlooks of capacity and energy mixes, as reflected in Table 3 below. For purposes of the 2023 IRP Update, only the MG0 scenario with the 2023 IRP Update Load Forecast is available upon the filing date. Georgia Power will file a supplemental filing at a later date to support all six scenarios.

Table 3: Planning Scenarios

Scenario	GHG pressure view	Technology view	Load view	Fuel view	Label
1	Lower	Tech Portfolio	2023 IRP Update	Lower	LG0
2	Lower	Tech Portfolio	2023 IRP Update	Moderate	MG0
3	Lower	Tech Portfolio	2023 IRP Update + HG0 delta	Higher	HG0
4	Moderate ($20)	IRA 2045	Alt 1	Moderate	MG20
5	Higher ($50)	IRA 2035	Alt 2	Moderate	MG50
6	Emissions Limit	IRA 2035	Alt 2	Moderate	EL

4.2 RESULTS SUMMARY

Please see Technical Appendix Resource Mix Study (Capacity Expansion Plans) for a summary of results for analyses around the MG0 scenario.



Economic Analysis of Capacity Resources

2023 Integrated Resource Plan Update

1. Introduction

As stated in the 2023 Integrated Resource Plan ("IRP") Update, Georgia's economy has continued to thrive, bringing rapid economic expansion and an unprecedented increase in the demand for energy to the state. This rapid economic expansion requires Georgia Power Company ("Georgia Power" or "GPC") to develop or procure additional capacity resources so that it can continue to provide reliable electric service to its customers. Therefore, Southern Company Services ("SCS") and Georgia Power (collectively, the "Company") evaluated numerous resources that can provide the capacity necessary to meet its customers' energy needs during this period of extraordinary economic growth in Georgia. This document discusses the Company's economic evaluation of these resources in support of the 2023 IRP Update.

2. Approach

The Company's economic evaluation compares the costs and benefits of resource options identified in the 2023 IRP Update. The evaluation ranks the resources to determine the least cost options that are able to meet the Company's capacity need. To capture the uncertainty of future fuel prices and carbon pressure, the analysis was performed over a range of fuel prices and carbon price paths, resulting in five distinct planning scenarios. This approach is consistent with typical economic evaluations of resources proposed to meet forecasted needs, such as a capacity request for proposals ("RFP") and similar procurements. These factors were incorporated within the Company's economic evaluation of resources, as described in this document.

3. Assumptions

The Company modeled the incremental costs and benefits of each resource it evaluated. Costs include capacity costs, capital costs, fixed operations and maintenance ("O&M") costs, start-up costs, natural gas transportation charges, and other incremental cost to customers. Utilizing the Aurora model, the Company quantified the production cost savings (i.e., energy benefits) of each resource, while also capturing the projected commodity fuel and variable O&M costs.

3.1. Power Purchase Agreements ("PPA")

For each PPA, the Company's economic evaluation includes the cost of the PPA as set forth by the terms of each PPA. Capacity costs are fixed costs associated with the capacity payment for each PPA. The start-up cost for a PPA represents the projected cost to start a thermal generating unit, taking into account the anticipated number of starts required under economic dispatch and the cost characteristics of the individual resources. For contracted resources, the per-start cost was specified in the PPA. Firm transportation ("FT") cost was included for resources that require additional FT, or firm access to natural gas pipeline infrastructure, to provide reliable service. An additional sum of $3/kW-yr was included consistent with the additional sum approved for capacity resources in the 2022 IRP[1] and requested in this 2023 IRP Update. The analysis also considered an accounting lease cost for applicable PPA proposals. Variable O&M, fuel costs, and emissions costs are netted out of the energy benefits and are derived by the production cost model, Aurora. For any sales to a third party, the expected sales revenues are credited as a benefit to customers.

3.2. New Company-owned Resources

The costs of new construction for proposed Company-owned resources were included in the economic evaluation. In-service capital costs represent the cost of construction, financing costs, and property taxes. Maintenance capital costs are the projected capital expenditures necessary to maintain reliable operation through the assumed useful life of a resource. O&M includes labor, materials, support services, and overhead costs necessary to operate the plant. O&M costs are broken out between fixed and variable O&M for each study. Fixed O&M is directly reflected in the economic valuation. Variable O&M, fuel costs, and emissions costs are netted out of the energy benefits and are derived by the production cost model, Aurora.

The Inflation Reduction Act ("IRA") provides opportunities for Investment Tax Credits ("ITC") and Production Tax Credits ("PTC") that directly benefit customers. The Company included the assumed benefits of the ITC for battery energy storage systems ("BESS") and PTC for solar resources. The impact of the ITC on BESS is reflected in the in-service capital costs. The PTC benefits for solar resources are reflected in the additional benefits.

[1] Docket No. 44160.

3.3. Acquisitions

The Company is pursuing a potential acquisition of additional capacity from **REDACTED REDACTED REDACTED

3.5. Term Equalization

To conduct an evaluation of proposed resources with varying unit lives and term lengths, the evaluation period must be based upon the life of the longest-lived resource being evaluated. For the 2023 IRP Update that resource is Plant Yates Units 8-10, which has an expected service life of 45 years. The Company analyzed the economics of each resource consistent with its proposed term, or the expected remaining service life in the case of resources the Company proposes acquiring. The Company then performed a similar economic assessment for replacement capacity for the balance of the evaluation period. The replacement capacity used for the balance of the period was assumed to be a dual-fueled combustion turbine ("CT"), consistent with the cost of Plant Yates Units 8-10. Using this method, the Company was able to evaluate each resource on a comparable basis over a 45-year period.

4. Summary of Study Results

The following tables represent the net present value ("NPV") of the net costs associated with each resource that was evaluated. The results are calculated by comparing the cost of each resource net of its benefits, which include energy benefits and market or acquisition-related revenues. The NPV is then divided by the capacity contribution of each resource to the Company's target reserve margins. This provides a $/kW result for comparison purposes. The results across each scenario are averaged and ranked to establish a relative ranking of each resource.

4.1. Ranking and Summary of Results (2024 NPV $/kW)

Rank	Project		LG0	MG0	HG0	MG20	MG50	Average
REDACTED		REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
REDACTED		REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
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4.2. Results for MG0 (2024 NPV $/kW)

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4.3. Results for MG20

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4.4. Results for MG50

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4.5. Results for LG0

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4.6. Results for HG0

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Transmission Screening Analyses Overview

Georgia Power Company ("Georgia Power" or the "Company") performed transmission screens for various generation resource options under consideration by the Company to support its generation resource needs as described in the 2023 IRP Update. The screens utilized 2023 V2A power flow base cases along with scenarios shown in Table 1:

Table 1 - Transmission Screen Scenarios

Screen Scenario	Description
Base	Includes all large loads which have selected Georgia Power and prior queued projects
A1	Base scenario with other retail operating company unit extensions and the following Georgia Power resource extensions: • Gaston 1-4, Bowen 1-4, and Scherer 3 available through 2035 Base scenario with the following potential power purchase agreements ("PPAs"): • Lindsay Hill years 2026 – 2035 • Santa Rosa years 2026[1] – 2028
A2	Scenario A1 with Lindsay Hill PPA starting on 5/2029 (due to transmission constraints and project timing limitations)
B	Scenario A1 with proposed Yates CTs and their respective commercial operation dates
C[2]	Scenario B with proposed 200 MW battery energy storage systems ("BESS") co-located with 200 MW solar project

The transmission screening analysis determined that all unit extensions required to support the 750 MW Mississippi Power Company PPA can be accommodated along with the PPA for capacity and energy from the Santa Rosa combined cycle facility located in northwest Florida with no required transmission projects (Scenario A1).

Initial transmission screens of a potential Lindsay Hill PPA (Scenario A1) required currently planned projects to be advanced and completed sooner than planned. After additional evaluation (Scenario A2), it was determined that the required transmission projects could not be advanced, which would mean that a potential Lindsay Hill PPA could only be considered as a capacity resource option starting after the summer of 2029. Due to these limitations, a potential Lindsay Hill PPA was not considered as a viable resource option for the accelerated capacity needs in the 2023 IRP Update.

After the generation resource portfolio was determined from Scenarios A1 and A2, approximately 1,350 MW of combustion turbines proposed at Plant Yates (Scenario B) were screened with commercial operation dates of 11/2026 (2 units) and 2/2027 (1 unit), respectively. Transmission screens revealed that

[1] The Santa Rosa PPA begins in 2024. The screen has been revised and no transmission constraints were identified.
[2] No transmission screens were required for the proposed 178 MW of BESS at Robins and Moody Air Force Bases, since the BESS will initially charge from the existing solar facilities at each site, and the output of the facilities has previously been studied and designated.

approximately $80 million in additional transmission projects are required to accommodate the full output of the facility. Based on the required transmission projects, the Company will plan to limit the proposed Plant Yates CTs to 600 MW of firm output in both summer and winter peak periods until all improvements are in service by the summer of 2028. This information is reflected in the Economic Analysis of Capacity Resources in the Technical Appendix.

In addition to the proposed Plant Yates CTs, the Company screened 415 MW of solar with 200 MW of alternating current-coupled BESS (Scenario C). This proposed project would initially charge solely from solar and eventually transition to a hybrid-charge strategy with ability to charge from the transmission grid. Transmission screens did not identify any attributable transmission projects needed to accommodate the facility's full output. However, prior-planned projects in the area that are also needed to enable the output are not scheduled to be completed until May of 2029 and cannot be advanced. Therefore, the BESS co-located with new solar project would be limited to 200 MW of firm output in both summer and winter until summer of 2029. The Company is proposing 200 MW of BESS co-located with 200 MW of new solar as further described in the Technical Appendix.

All transmission screen files supporting the analysis in this Technical Appendix are provided as TRADE SECRET workpapers and are redacted in their entirety for PUBLIC DISCLOSURE purposes.

Additional transmission studies in support of the proposed generation resources and the 2023 IRP Update Load and Energy forecast are underway. Analyses are expected to be completed in January 2024 and will be filed by the Company as a supplement to this 2023 IRP Update.

GPC EXHIBIT 4
Bin 10230
241 Ralph McGill Boulevard, NE
Atlanta, GA 30308-3374

PUBLIC DISCLOSURE

December 4, 2023

Ms. Sallie Tanner
Executive Secretary
Georgia Public Service Commission
244 Washington Street, SW
Atlanta, GA 30334-5701

RE: Georgia Power Company's 2023 Integrated Resource Plan Update;
Docket No. 55378

Dear Ms. Tanner:

In accordance with O.C.G.A. § 46-3A-1, et seq., and Georgia Public Service Commission (the "Commission") Rules 515-3-4-.06 through 515-3-4-.10, as applicable, Georgia Power Company ("Georgia Power") filed its 2023 Integrated Resource Plan ("IRP") Update on October 27, 2023. Georgia Power now files a Supplemental Filing including:

- 2023 Request for Information for Capacity Resources – Summary of Results
- Resource Mix Study – Additional Expansion Plan Scenarios

This filing contains certain information that is being filed under the Commission's trade secret rules as explained in the enclosed basis for assertion. Therefore, in addition to the trade secret documents, as agreed to with Commission Staff and the Executive Secretary, 15 copies and an electronic version of this redacted 2023 IRP Update Supplemental Filing and supporting documentation are enclosed for public disclosure.

If you have any questions, please contact Cheryl Johnson at 404-506-6837.

Sincerely,

/s/ Kelley M. Balkcom

Kelley M. Balkcom
Director, Regulatory Affairs
mmcclosk@southernco.com

Enclosure

BEFORE THE GEORGIA PUBLIC SERVICE COMMISSION

GEORGIA POWER COMPANY
DOCKET NO. 55378

2023 IRP UPDATE SUPPLEMENTAL FILING

BASIS FOR THE ASSERTION THAT THE INFORMATION SUBMITTED IS A TRADE SECRET

As part of Georgia Power Company's 2023 Integrated Resource Plan Update filed in Docket No. 55378 ("2023 IRP Update"), Georgia Power Company ("Georgia Power" or the "Company") submits to the Georgia Public Service Commission its 2023 IRP Update Supplemental Filing ("Supplemental Filing"). In the Supplemental Filing, the Company has provided data supporting proposed projects including Company-owned proposals, which include sensitive pricing, resource operational capability data, and development timelines, and also certain information regarding the Company's proprietary planning processes, financial data, technology screening assumptions, generic technology and resource cost information, specific resource, technology and avoided cost information, economic analyses, load and energy forecast data assumptions, and other data, including confidential details regarding current and future transmission projects (the "Information"). All of such information constitutes trade secret information of Southern Company, Georgia Power, and its affiliates and is therefore protected from public disclosure under Commission Rule 515-3-1-.11.

The Information derives economic value from not being generally known to, and not being readily ascertainable by proper means by other persons who can obtain economic value from its disclosure or use. Specifically, the trade secret portions of the Information contained herein include competitively sensitive pricing and operational capability data, including project development timelines where applicable, specific to the resources under contract within each power purchase agreement or proposed to be developed. If the Information were made public, competitors, bidders, and suppliers could use the Information to unfairly manipulate the request for proposals process and competitive market to structure future bids and set an artificial price floor to arbitrarily increase prices to the detriment of the Company and its customers. Public dissemination of the Information would undermine Georgia Power's ability to negotiate the best price and contract terms and could harm the Company's ability to secure the best cost bids and resources for the benefit of customers. In addition, the terms of the power purchase agreements themselves provides for the confidentiality and protection of the Information. Compromising the confidentiality of such Information could harm Georgia Power in future PPA negotiations, as counterparties may fear compelled disclosure of key contractual terms. Lastly, the Company's competitors are not required to reveal or publish similar information.

The trade secret portions of the Information also contain competitively sensitive cost information related to available technology options, processes and data used by Georgia Power in analyzing resource addition schedules, financial data used in the Company's resource analyses, and other confidential details including data supporting resource economic evaluations. Public dissemination of the trade secret portions of the Information would allow Georgia Power's

competitors and suppliers to have access to such processes and strategies and thereby gain an unfair competitive advantage in the marketplace. Competitors would obtain an unfair advantage because they are not required to reveal similar information and can utilize such trade secret portions of the Information to manipulate pricing and timing of supply to the disadvantage of Georgia Power. Competitors would also unfairly benefit in having access and insight into the Company's planning processes and methodologies. This competitive advantage for the Company's suppliers and competitors would mean that Georgia Power will potentially pay higher prices to suppliers, ultimately harming Georgia Power and its customers.

The Information is subject to substantial procedures to maintain its secrecy. Only select Georgia Power and Southern Company Services personnel are granted access to the Information. Those personnel receive access only on a "need to know" basis. Parties outside the Company who have been granted access to the Information, if any, have been required to sign confidentiality agreements with respect to the Information.

Jeffrey R. Grubb, first being duly sworn, deposes and states that he has reviewed the Company's 2023 IRP Update Supplemental Filing and that to the best of his knowledge the specific information designated as trade secret constitute trade secrets in accordance with O.C.G.A. § 10-1-761 (2021).

Jeffrey R. Grubb
Director, Resource Policy & Planning
Georgia Power Company

Subscribed and sworn to before me this 4th day of December, 2023.

Notary Public

My Commission expires:



Georgia Power

DOCKET NO. 55378

2023 REQUEST FOR INFORMATION FOR CAPACITY RESOURCES – SUMMARY OF RESULTS

Georgia Power Company

4 December 2023

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1.0 Overview of the RFI

1.1 Purpose and Scope

On September 26, 2023, Georgia Power Company ("Georgia Power" or the "Company") issued a Request for Information ("RFI") to gather market information regarding the availability of existing and planned Capacity Resources for the capacity need identified for years 2026 through 2028, the timeframe being addressed in the Company's 2023 IRP Update, as well as for years 2029 through 2031, the time period to be addressed in the Company's 2029-2031 All-Source Request for Proposals ("RFP"). The primary objective of the RFI was to provide Georgia Power with current market information on the size, cost, technology, availability, risk, and operational and technical attributes of any reliable resource that can meet the firmness and dispatchability requirements, as defined in the RFI, including, but not limited to: (i) Standalone Energy Storage System ("ESS") with grid charging capability; (ii) ESS with a Renewable Resource[1] with grid charging capability; or (iii) thermal generation (e.g. natural gas, oil fired) (each a "Capacity Resource" and collectively, "Resource Types").

Georgia Power sought information regarding projects that could commence delivery on or after November 1, 2026, but no later than November 1, 2030 pursuant to either a Power Purchase Agreement ("PPA"), Asset Purchase Agreement ("APA"), or a Build Transfer Agreements ("BTA"). Each Capacity Resource identified in the RFI had to be at least one hundred megawatts (100 MW) in size, and a single resource could not exceed twelve hundred megawatts (1,200 MW). Georgia Power's interest included the availability of PPAs with a term of five (5), ten (10), fifteen (15), or twenty (20) years and the ability to deliver energy in the Southern Company Transmission System[2] and Georgia Integrated Transmission System[3] (collectively, "Southern Transmission Territory" or "STT") or at an interface between the STT and another transmission service provider. Capacity Resources with ESS with grid charging capability, including those paired with a Renewable Resource, were required to be interconnected to the Southern Company Transmission System to assure Georgia Power can provide (toll) the energy, and solely charge energy from the Southern Company Transmission System. Regarding Standalone ESS Capacity Resources, Georgia Power would provide (toll) all the energy required to charge a Standalone ESS, excluding station service. Georgia Power considered APAs for existing facilities and BTAs for new projects located within the STT offering 100% ownership of the existing or new Capacity Resource. Georgia Power did not consider responses for partial unit(s) of an existing Capacity Resource or a non-ownership interest in an existing Capacity Resource, unless Georgia Power already had an interest in the existing Capacity Resource or already owned units on the facility site.

[1] Renewable Resource: A renewable generating facility that: (i) has or will have a point of interconnection on the Southern Company Transmission System; (ii) must be at least 100 MW in size; and (iii) utilizes a sustainable, perpetual, or renewable fuel.
[2] Southern Company Transmission System: The integrated high voltage electricity transmission systems of the electric utility operating companies of the Southern Companies (Georgia Power Company, Alabama Power Company, and Mississippi Power Company).
[3] Georgia Integrated Transmission System ("Georgia ITS"): An integrated transmission system owned individually by Georgia Power Company, Georgia Transmission Corporation, Municipal Electric Authority of Georgia ("MEAG") Power, and Dalton Utilities and operated to transmit, receive, or distribute electric energy or capacity.

1.2 RFI Process

Georgia Power's RFI was intended solely to solicit information to assist with future resource planning efforts and to gain knowledge of available capacity and generation resources. To solicit the market for the RFI, Georgia Power utilized various internal and external communication channels to notify the market and provide an opportunity to respond to the RFI. The communication channels included: GeorgiaPower.com; industry email distribution to over five hundred (500) Georgia Power contacts from previous RFPs and PPA or business counterparties; social media ad on LinkedIn; Georgia Power News Center article; and targeted media outreach to a group of energy industry publications. GeorgiaPower.com was the main landing page for interested parties to access information about the RFI and to access a link to register for the OnBase website ("RFI Website"). The RFI Website, developed and managed by Georgia Power, was the host platform for interested parties to submit responses. In addition, the RFI Website provided notifications to registered users and a forum for questions and answers regarding the RFI. Georgia Power invited all interested parties to submit a response to the RFI between September 26 and October 24, 2023.

1.3 Market Outreach

As mentioned in Section 1.2 (RFI Process), Georgia Power broadly publicized the RFI by notifying various industry contacts, past RFP participants, entities that expressed interest in past RFPs, and current PPA counterparties. The notification was sent as an "email blast" (see Attachment B). In addition, the Company promoted the RFI on social media through LinkedIn. The social media ad targeted a range of industries and job titles with an overall ad impression, or number of times the ad/post was visible, of 71,718. Please see Tables 1-3-1 and 1-3-2 below for performance metrics of the social media ad on LinkedIn.

Table 1-3-1

Ad Performance	
Clicks[4]	707
Impressions[5]	71,718
Average Click through Rate (CTR)[6]	0.99%
Total Social Actions[7]	1,420
Total Engagement [8]	2,211

Table 1-3-2

Top Industries Reached
Electric Industries
Utilities
Natural Gas Distribution
Top Job Titles Reached
Project Manager
Engineer
Operational Specialist

Overall, throughout the RFI timeframe, there were a total of 1,400 page views of the Georgia Power RFI Website and 921 unique visitors who visited the RFI Website at least once.

[4] Number of clicks the Ad received.
[5] The number of times each post was visible.
[6] The number of clicks divided by impression.
[7] Volume of social engagement ad received. Includes reactions, comments, shares, follow clicks, reaction clicks, and other engagements.
[8] The sum of all social actions, clicks to Landing page, and clicks to LinkedIn Page, both chargeable and free.

2.0 RFI Results

2.1 Summary of Responses

Georgia Power received forty-four (44) unique submissions[9] to the RFI. Of the responses received, thirty-seven (37) were mutually exclusive[10] potential projects. Of these thirty-seven (37) potential projects, five (5) submissions included solar only resources, which did not meet the Capacity Resource requirements of the RFI (see Attachment A), which left thirty-two (32) total qualifying submissions. Of the thirty-two (32) qualifying submissions, only two (2) projects were existing Capacity Resources. These two existing resources are not available as additional resources to the Company in the timeframe addressed in the Company's 2023 IRP Update. The remaining qualifying submissions either indicated new or planned potential projects. RFI participants represented twenty-two (22) different companies with several companies providing multiple responses for different project types and interest in differing contract types.

2.2 Location

Of the qualifying submissions, three (3) submissions indicated potential new or planned projects located in Alabama, with all remaining submissions that listed a project state indicating potential projects within the state of Georgia. Three submissions did not identify a state for the proposed project. See the map in Figure 2-2-1 below.

Figure 2-2-1



2.3 Capacity and Resource Type and Availability

Georgia Power received a robust response to the RFI, with the potential total capacity equaling 6,667 MW. See Table 2-3-1 below for a breakdown of Resource Types and capacity. The RFI results indicated the availability of two (2) existing projects, both thermal Resource Types, while all other qualifying submissions indicated either new or planned projects in various stages of development. RFI participants were primarily interested in a PPA option for ESS with a Renewable Resource, with grid charging capability. More specifically, RFI participants offered projects with battery energy storage

[9] Unique submissions include multiple submissions for the same project offering different contract types (e.g., PPA, APA, BTA).
[10] Mutually exclusive submissions indicate the number of individual projects.

systems paired with solar. Georgia Power received several responses that included an interest to provide Georgia Power resources pursuant to BTAs. Georgia Power did not receive any indication from the RFI participants of any plans to develop new natural gas Capacity Resources.

Table 0-3-1

Breakdown of Resource Types[11]		
Capacity Resource Type	**# of Responses**	**Sum of Capacity (MW)**
ESS Standalone[12]	13	2,695
ESS + solar[13]	12	1,680
ESS Other[14]	4	769
Thermal (CC / CT)	2	1,243
Nuclear Energy	1	280
Total	**32**	**6,667**

As a result of the RFI, Georgia Power collected valuable market information regarding existing or planned Capacity Resources that could commence delivery between the 2026 – 2030 timeframes. As shown in Table 2-3-2, a total of 3,777 MW in Capacity Resources indicated they are available to be constructed within the 2026-2028 timeframe and a total of 2,146 MW indicated they are available within the 2029-2031timeframe. For the 2025-2027 timeframe, those resources are not available to meet the Company's needs as being addressed in the 2023 IRP Update. There is not enough time for an RFP to be conducted, resources to be constructed following certification, and transmission projects to be identified and completed to allow delivery by the end of calendar years 2025, 2026 or 2027. Table 2-3-2 provides a breakdown of the Capacity Resources' indicated availability based on calendar years identified in response to the RFI.

Table 0-3-2

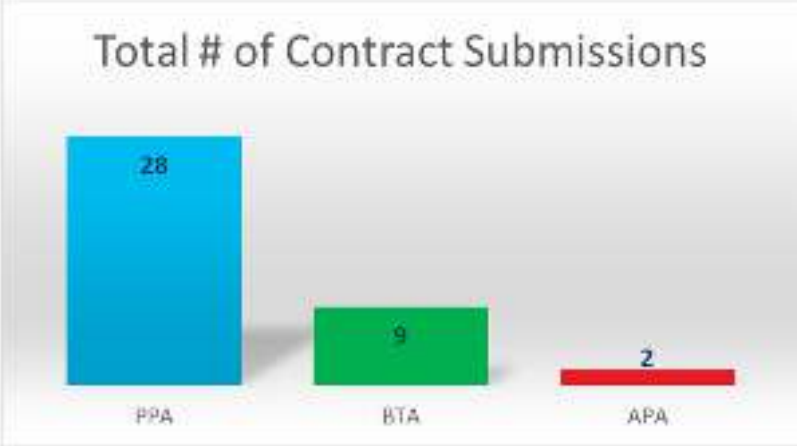
Availability Year	Total
2025	100
2026	1,110
2027	1,495
2028	1,072
2029	420
2030	1,446
2031	280
Not Provided	744
Totals (MW)	**6,667**

[11] As described in Section 2.1, 5 of the submissions included solar only resources, which did not meet the Capacity Resource qualifications of the RFI (See Attachment A).
[12] ESS Standalone generally represents battery energy storage systems as the "ESS" device.
[13] ESS + solar generally represents battery energy storage systems as the "ESS" device.
[14] ESS "Other" includes responses that indicate non-standard storage technologies (e.g., Hydrogen Fuel Cells, Pumped Heat, Compressed Air, and Superconducting Magnetics.

2.4 Contract Type

In response to Georgia Power's request for feedback on offering resources pursuant to the PPA, APA, and BTA contract types, the market responded with interest in all three contract types. Of the thirty-two (32) qualifying submissions, Figure 2-4-1 below shows a breakdown of submissions by contract type.[15] Of note, RFI participants were primarily interested in a PPA option for ESS Standalone or ESS paired with a Renewable Resource, with grid charging capability.

Figure 2-4-1



2.5 Conclusion

The Georgia Power RFI provided the Company with valuable market information to assist with current and future resource planning efforts and facilitate Georgia Power's preparation for the 2029-2031 All-Source RFP. As noted above, no existing resources were identified which could help meet the capacity needs being addressed in the Company's 2023 IRP Update. Of the 6,667 MW of Capacity Resources potentially available in the market, only 1,243 MW of existing capacity was identified and appears to be available during the 2029-2031 timeframe. RFI participants indicated the most interest in providing planned or new ESS Standalone and ESS with a Renewable Resource, with grid charge capability, with significant interest in providing planned or new projects through either a PPA or BTA.

15 Five (5) projects indicated alternate Contract Types.

Attachment A RFI Document

Resource Policy & Planning
241 Ralph McGill Blvd
Bin #10194
Atlanta, GA 30308

September 26, 2023

To: All Interested Parties

Re: Request for Information

Georgia Power Company ("GPC") issues this Request for Information ("RFI") to request information regarding any reliable resource that can meet this RFI's firmness and dispatchability requirements (each a "Capacity Resource"), including, but not limited to: (i) Standalone Energy Storage System ("ESS"), with grid charging capability; (ii) ESS, with a Renewable Resource, with grid charging capability; or (iii) thermal generation (e.g., natural gas, oil fired).

Firmness includes, but is not limited to, Firm Transmission Service as defined in this RFI. Dispatchability includes, but is not limited to, the ability to operate the facility on Automatic Generation Control ("**AGC**") as defined in this RFI or electronically scheduled to adjust the regulation of the facility to deliver energy from the Capacity Resource.

Each Capacity Resource identified must be at least one hundred megawatts (100 MW) in size, and a single resource may not exceed twelve hundred megawatts (1,200 MW). GPC invites all interested parties to submit a response to this RFI.

GPC will manage the OnBase website ("**RFI Website**") as the host platform for this RFI. All responses to this RFI must be submitted through the RFI Website. In addition, the RFI Website will provide notifications to registered users and a forum for questions and answers regarding this RFI.

The RFI Website is located on GPC's website at www.GeorgiaPower.com/rfi.

GPC will accept RFI responses through the RFI Website from **September 26, 2023,** through **October 24, 2023**.

REQUEST FOR INFORMATION

All-Source RFI for Capacity

Background

GPC's 2022 Integrated Resource Plan, as approved by the Georgia Public Service Commission ("**Commission**") in Docket No. 44160 ("**2022 IRP**"), identified a need for additional Capacity Resources. On July 21, 2022, the Commission issued its 2022 IRP Final Order, which amended and approved the Stipulation requiring GPC to conduct an all-

source solicitation to address capacity needs identified by GPC. In the 2022 IRP, GPC estimated approximately 3,723 MW of Capacity Resources would be necessary to satisfy GPC's capacity needs through Winter 2031, but current projections indicate greater capacity needs and needs earlier than the 2029-2031 timeframe. In light of these projections, GPC issues this RFI to collect information on existing or planned Capacity Resources that can meet the firmness and dispatchability requirements set forth in this RFI and commence delivery to GPC between the 2026 – 2030 timeframe.

1.0 Description

GPC seeks identification and associated details regarding any Capacity Resource that can meet the requirements of this RFI that include the following technologies:

(i) Standalone ESS with grid charge capability;
(ii) ESS with a Renewable Resource, with grid charge capability; or
(iii) Thermal generation (e.g., natural gas, oil fired).

Capacity Resources must: (i) provide firm capacity and energy from one or more dedicated generation units; (ii) be fully dispatchable to meet GPC's scheduling instructions; and (iii) be capable of operating on AGC. Firmness includes, but is not limited to, Firm Transmission Service.

The primary objective of this RFI is to provide GPC with market information on the size, cost, technology, availability, and deliverability of Capacity Resources. GPC may consider response information based on economics, risk, and operational and technical attributes using GPC's most recent resource planning assumptions.

Information submitted in response to this RFI will become the property of GPC and will be made available to the Commission and Commission Staff (**"Staff"**). GPC and respondents acknowledge that portions of these responses may contain confidential information. Please note that GPC will protect the confidential nature of responses and will not share publicly information that is designated in writing as confidential. However, respondents understand and acknowledge that confidential information may need to be disclosed by GPC in connection with its regulatory obligations before the Commission. Should this occur, GPC will request confidential treatment of confidential information in accordance with the Commission's rules regarding trade secrets, but GPC makes no assurance or commitment regarding GPC's ability to obtain confidential treatment from the Commission.

THIS IS A REQUEST FOR INFORMATION ONLY. GPC issues this RFI solely to solicit information to assist with future resource planning efforts and to gain knowledge of available capacity and generation resources, along with an estimate of their corresponding costs. This RFI is not a request for proposals ("**RFP**") and is intended solely to inform GPC about available and planned Capacity Resources. After review of the RFI responses, GPC may or may not explore the potential for future procurement options in connection with one or more Capacity Resources at its sole discretion. This RFI must not be construed as an intent, commitment, or promise to contract nor to acquire assets, resources, or products offered. All costs associated with responding to this RFI will be solely at the responding party's expense. Abstaining from responding to this RFI will not preclude participation in any All-Source RFP issued by GPC in the future.

2.0 Scope

GPC requests information regarding existing or planned Capacity Resources that could be procured by GPC through a:

(i) Power Purchase Agreement ("**PPA**");

(ii) Asset Purchase Agreement ("**APA**"); or

(iii) Build Transfer Agreement ("**BTA**")

to commence delivery to GPC during the 2026 – 2030 timeframe. Responses must indicate a commencement of service to GPC on or after November 1, 2026, but no later than November 1, 2030.

Capacity Resources available to commence delivery as early as November 1, 2024, should indicate such availability prior to the requested 2026 – 2030 timeframe.

3.0 Response Instructions

GPC requests the information described below about existing or potential Capacity Resources that might be available to serve GPC customers in Georgia in the requested timeframe. This list is illustrative and not all topics are required to respond to this RFI. Information referenced as *optional* is not required. This RFI uses the following definitions:

- **Automatic Generation Control ("AGC")**: The equipment and capability of a Capacity Resource to automatically adjust the energy quantity output within the applicable balancing authority for the purpose of interchange balancing, and specifically, the Capacity Resource capability of accepting a set point electronically and the automatic adjustment and regulation of the facility's energy production output to meet that set point.
- **Firm Transmission Service**: Transmission service that has: (i) been procured and is held by a seller under the applicable open access transmission tariff on each applicable Electric System for the delivery of energy from the facility to the point of delivery; and (ii) a priority equal to the highest level of firm transmission service available to any person on that Electric System from: (a) COD and through the PPA term; or (b) APA or BTA closing and through the remainder of the facility design life, as applicable.
- **Electric System**: The network of electric generation, transmission, or distribution facilities owned or operated by GPC or other electric utilities.
- **Georgia ITS**: The Georgia Integrated Transmission System, which is owned individually by GPC, Georgia Transmission Corporation, Municipal Electric Authority of Georgia ("**MEAG**") Power, and Dalton Utilities and operated as an integrated transmission system for transmitting, receiving, or distributing electric energy or capacity.
- **Renewable Resource**: A renewable generating facility that: (i) has or will have a point of interconnection ("**POI**") on the Southern Company Transmission System; (ii) must be at least 100 MW in size; and (iii) utilizes a sustainable, perpetual, or renewable fuel.

- **Southern Balancing Authority Area ("SBAA")**: A North American Electric Reliability Corporation ("**NERC**") and Southeastern Electric Reliability Corporation ("**SERC**") recognized balancing authority area. For the avoidance of doubt, the SBAA includes the Southern Transmission Territory.
- **Southern Company Transmission System**: The integrated high voltage electricity transmission systems of the electric utility operating companies of the Southern Companies (GPC, Alabama Power Company, and Mississippi Power Company).
- **Southern Transmission Territory ("STT")**: The Southern Company Transmission System and the Georgia ITS.
- **Standalone ESS:** An ESS that is not paired with a Renewable Resource.

- **<u>General Information Requested:</u>**
    - Facility or Project name
    - Facility location (state, county, city, and transmission interconnection provider)
    - Facility status (Is the project new or existing? Is the project currently in operation or in construction?)
    - Commercial operation date ("**COD**") or projected COD
    - Contingencies associated with facility COD
    - Nameplate capacity of facility and each unit (each Capacity Resource identified must be at least 100 MW in size and no single resource may exceed 1,200 MW)
    - Delivery commencement date (date when existing or projected capacity would be available to GPC) and any contingencies or restrictions on commencement
    - Actual or projected winter and summer capacity (MW) of facility
    - Facility data (generation technology type, vendor, unit type and configuration), and remaining facility life at delivery commencement date (years)
    - Facility or unit efficiency measures: average heat rates at maximum and minimum operating capacities for thermal resources or roundtrip efficiency for ESS (*optional*)
    - Provide any additional summary data regarding facility operating parameters (*optional*)
    - Fuel supply plan (if applicable) (*optional*)

- **<u>Product-Specific Information Requested:</u>**
    - **Consideration of PPAs.** GPC will consider Capacity Resources: (i) for PPAs with a term of 5, 10, 15, or 20 years; and (ii) able to deliver energy in

the STT or at an interface between the STT and another transmission service provider, except that Capacity Resources with ESS must be interconnected to the Southern Company Transmission System.

Please provide indicative pricing for the following:

- Capacity pricing $/kW- month and escalation rate (%)
- First year variable O&M cost ($MWh) and escalation rate (%) (optional)
- First year O&M startup costs ($/start) and escalation rate (%) (optional)
- Fuel pricing (if applicable); GPC toll is preferred but if existing fuel plan, please provide (*optional*)

- **Consideration of APAs.** GPC will consider APA projects for an existing Capacity Resource located within the STT. An APA must offer 100% ownership of the existing Capacity Resource. GPC will not consider responses for partial unit(s) of an existing Capacity Resource or a non-ownership interest in an existing Capacity Resource, unless GPC already has an interest in the existing Capacity Resource or already owns units on the facility site.

  Please provide indicative pricing for the following:

  - Facility total project price $(2023)
  - First year variable O&M cost ($/MWh) and escalation rate (%) (*optional*)
  - First year fixed O&M cost ($/kW) and escalation rate (%) (*optional*)
  - Start-up costs: ($/start) (*optional*)
  - Fuel pricing (if applicable) (*optional*)
  - Projected annual maintenance (weeks per year on average) (*optional*)
  - Historical availability (%) (*optional*)
  - Expected future availability (%, average annual over the remaining useful life) (*optional*)

- **Consideration of BTAs.** GPC will consider BTA facilities for a new Capacity Resource located within the STT. A BTA must offer 100% ownership of the new Capacity Resource.

  Please provide indicative pricing for the following:

  - Facility total project price $(2023)
  - First year variable O&M cost ($/MWh) and escalation rate (%) (*optional*)
  - First year fixed O&M cost ($/kW) and escalation rate (%) (*optional*)
  - Start-up costs: ($/start) (*optional*)

- Fuel pricing (if applicable) (*optional*)
- Projected annual maintenance (weeks per year on average) (*optional*)
- Expected future availability (%, average annual over the useful life) (*optional*)

- **Energy Storage Specifications and Information Requested:**
  - Any ESS Capacity Resource must be able to comply with Southern Company's Transmission's Operating Policy for Inverter Based Electric Storage Resources interconnecting to the Southern Company Transmission System, as appropriate, which may be found at:

    https://www.oasis.oati.com/woa/docs/SOCO/SOCOdocs/Inverter-Based_Electric_Storage_Operating_Policy.pdf.
  - **Standalone ESS.** A response identifying a Standalone ESS Capacity Resource must provide: (i) a description of the ESS; (ii) if offering a PPA, the plan to maintain the ESS to ensure the ESS performs as considered for the PPA term; (iii) the total expected ESS capacity (AC); and (iv) an annual schedule of the expected roundtrip efficiency for the term (PPA responses) or remaining facility design life (APA/BTA responses), as applicable. GPC must have the exclusive right to: (a) discharge; and (b) charge, without penalty, by issuing scheduling instructions. To assure GPC can toll the energy, a Standalone ESS must be interconnected to, and solely charged from, the Southern Company Transmission System. GPC will provide (toll) all the energy required to charge a Standalone ESS, excluding station service.
  - **ESS with Renewable Resource.** In addition to the information required above for Standalone ESS, including grid charge capability, a response identifying an ESS with Renewable Resource must also include: (i) a description of the Renewable Resource (including the generation type of the Renewable Resource (e.g., solar panels, wind turbines)); (ii) the total expected capacity (AC) from the Renewable Resource; and (iii) a profile reflecting the Renewable Resource, to demonstrate the charging contribution of the Renewable Resource for the ESS.

- **Transmission Information Requested:**
  - Existing or likely point(s) of interconnection and interconnection status (explain any current plans or limiting factors).
  - Interconnection or interconnection status must be for a large generator interconnection agreement.
  - As applicable for new resources, please provide the facility interconnection queue number or cluster group number.

- If located outside the SBAA, identify the transmission interconnection provider for the facility (not applicable for any Capacity Resource that: (i) includes ESS; or (ii) is related to an APA or BTA).

- **Project Financing Information Requested (Optional):**
  - Describe any experience financing commercial energy projects. (*optional*)
  - Please provide a description of the existing financing or financing plan for the facility (if applicable). (*optional*)

- **Other Information Requested:**
  - Briefly explain your interest and past experience in supplying energy and capacity, building or operating generation units, or negotiating generation asset sales and purchases. (*optional*)
  - Please indicate if you have entered into any PPA, APA, or BTA with GPC in the past. (*optional*)
  - Any additional information respondent deems relevant, including any optional references.
  - Briefly indicate if respondent is participating in other solicitations that may impact the information provided as part of this RFI.

4.0 Schedule

Event	Date
RFI Issued (RFI Website)	September 26, 2023
Last Day for Submitting Questions (RFI Website)	October 23, 2023
Due Date for Responses (RFI Website)	October 24, 2023, by 12 pm ET

5.0 Communications

RFI Website: The RFI Website is located on GPC's website at www.GeorgiaPower.com/rfi.

Attachment B Email Distribution Communication

Georgia Power

Request for Information Now Open

Georgia Power has issued a Request for Information (RFI) seeking information about available capacity resources to assist with its future resource planning efforts. Our RFI is open for submission now through October 24, 2023.

Eligibility

These capacity resources must meet our firmness and dispatchability requirements in the RFI including the following technologies:

i. Standalone Energy Storage System ("ESS"), with grid charging capability.
ii. ESS, with a Renewable Resource, with grid charging capability
iii. Thermal generation (e.g., natural gas, oil fired).

Each capacity resource identified must be at least 100 megawatts in size, and a single resource may not exceed 1,200 megawatts.

How to participate?

All interested parties are invited to submit a response regarding capability to provide purchase power agreements (PPAs), asset purchase agreements (APAs), or build transfer agreements (BTAs) on our dedicated RFI website between September 26, 2023 and October 24, 2023. The submission portal will also serve as a communication hub where registered users will receive updates and ask questions.

Additional Resources

For more information, visit the Georgia Power 2023 RFI website.

Georgia Power

Capacity Expansion Plan - MG0

Incremental

Year	CT w/ SCR	CC	CC w/ CCS	MPC PPA	Solar	Wind	Battery 4-hr (T1)	Battery 4-hr (T2)	Battery 4-hr (T3)	Battery 4-hr (T4)	Medium Duration Storage	Nuclear	Total
2024	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2025	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2026	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2027	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2028	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2029	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2030	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2031	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2032	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2033	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2034	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2035	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2036	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2037	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2038	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2039	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2040	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2041	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2042	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2043	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED

Cumulative

Year	CT w/ SCR	CC	CC w/ CCS	MPC PPA	Solar	Wind	Battery 4-hr (T1)	Battery 4-hr (T2)	Battery 4-hr (T3)	Battery 4-hr (T4)	Medium Duration Storage	Nuclear	Total
2024	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2025	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2026	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2027	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2028	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2029	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2030	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2031	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2032	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2033	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2034	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2035	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2036	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2037	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2038	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2039	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2040	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2041	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2042	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2043	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED

Capacity Expansion Plan - MG0 (GPC Only)

Incremental

Year	CT w/ SCR	CC	CC w/ CCS	MPC PPA	Solar	Wind	Battery 4-hr (T1)	Battery 4-hr (T2)	Battery 4-hr (T3)	Battery 4-hr (T4)	Medium Duration Storage	Nuclear	Total
2024													
2025													
2026													
2027				750			900						**1650**
2028	300				750		780						**1830**
2029	930						780	390					**2100**
2030		900			750								**1650**
2031		2700			180								**2880**
2032		300			180								**480**
2033		210			570	150							**930**
2034		210			570	120							**900**
2035	300	1710			600	600							**3210**
2036	600	1800			990	600		1500				300	**5790**
2037					990	300		240					**1530**
2038					990	600		270				300	**2160**
2039		210			990	330						210	**1740**
2040					990	600			1080			300	**2970**
2041					1020				540				**1560**
2042					1020	300							**1320**
2043					1020	300				300		300	**1920**
	2130	**8040**		**750**	**11610**	**3900**	**2460**	**2400**	**1620**	**300**		**1410**	**34620**

Cumulative

Year	CT w/ SCR	CC	CC w/ CCS	MPC PPA	Solar	Wind	Battery 4-hr (T1)	Battery 4-hr (T2)	Battery 4-hr (T3)	Battery 4-hr (T4)	Medium Duration Storage	Nuclear	Total
2024													
2025													
2026													
2027				750			900						**1650**
2028	300			750	750		1680						**3480**
2029	1230				750		2460	390					**4830**
2030	1230	900			1500		2460	390					**6480**
2031	1230	3600			1680		2460	390					**9360**
2032	1230	3900			1860		2460	390					**9840**
2033	1230	4110			2430	150	2460	390					**10770**
2034	1230	4320			3000	270	2460	390					**11670**
2035	1530	6030			3600	870	2460	390					**14880**
2036	2130	7830			4590	1470	2460	1890				300	**20670**
2037	2130	7830			5580	1770	2460	2130				300	**22200**
2038	2130	7830			6570	2370	2460	2400				600	**24360**
2039	2130	8040			7560	2700	2460	2400				810	**26100**
2040	2130	8040			8550	3300	2460	2400	1080			1110	**29070**
2041	2130	8040			9570	3300	2460	2400	1620			1110	**30630**
2042	2130	8040			10590	3600	2460	2400	1620			1110	**31950**
2043	2130	8040			11610	3900	2460	2400	1620	300		1410	**33870**
	2130	**8040**		**750**	**11610**	**3900**	**2460**	**2400**	**1620**	**300**		**1410**	**34620**

Capacity Expansion Plan - LG0

Incremental

Year	CT w/ SCR	CC	CC w/ CCS	MPC PPA	Solar	Wind	Battery 4-hr (T1)	Battery 4-hr (T2)	Battery 4-hr (T3)	Battery 4-hr (T4)	Medium Duration Storage	Nuclear	Total
2024	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2025	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2026	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2027	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2028	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2029	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2030	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2031	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2032	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2033	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2034	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2035	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2036	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2037	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2038	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2039	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2040	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2041	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2042	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2043	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED

Cumulative

Year	CT w/ SCR	CC	CC w/ CCS	MPC PPA	Solar	Wind	Battery 4-hr (T1)	Battery 4-hr (T2)	Battery 4-hr (T3)	Battery 4-hr (T4)	Medium Duration Storage	Nuclear	Total
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2025	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2026	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2027	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2028	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2029	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2030	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2031	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2032	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2033	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2034	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2035	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2036	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2037	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2038	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2039	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2040	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2041	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2042	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2043	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED

Capacity Expansion Plan - LG0 (GPC Only)

Incremental

Year	CT w/ SCR	CC	CC w/ CCS	MPC PPA	Solar	Wind	Battery 4-hr (T1)	Battery 4-hr (T2)	Battery 4-hr (T3)	Battery 4-hr (T4)	Medium Duration Storage	Nuclear	Total
2024													
2025													
2026													
2027				750			900						**1650**
2028	300						600						**900**
2029	900						990	390					**2280**
2030		900			750								**1650**
2031		2700			180								**2880**
2032		300			180								**480**
2033		210			570	330							**1110**
2034		300			570								**870**
2035		1800			600	600							**3000**
2036	600	1500			990	600		900			1200		**5790**
2037					990			270					**1260**
2038					990			870					**1860**
2039	210	210			990	330							**1740**
2040	600				990	300						210	**2100**
2041			30		1020						210	210	**1470**
2042					1020	600						270	**1890**
2043					1020	600					210	270	**2100**
	2610	**7920**	**30**	**750**	**10860**	**3360**	**2490**	**2430**			**1620**	**960**	**33030**

Cumulative

Year	CT w/ SCR	CC	CC w/ CCS	MPC PPA	Solar	Wind	Battery 4-hr (T1)	Battery 4-hr (T2)	Battery 4-hr (T3)	Battery 4-hr (T4)	Medium Duration Storage	Nuclear	Total
2024													
2025													
2026													
2027				750			900						**1650**
2028	300			750			1500						**2550**
2029	1200						2490	390					**4080**
2030	1200	900			750		2490	390					**5730**
2031	1200	3600			930		2490	390					**8610**
2032	1200	3900			1110		2490	390					**9090**
2033	1200	4110			1680	330	2490	390					**10200**
2034	1200	4410			2250	330	2490	390					**11070**
2035	1200	6210			2850	930	2490	390					**14070**
2036	1800	7710			3840	1530	2490	1290			1200		**19860**
2037	1800	7710			4830	1530	2490	1560			1200		**21120**
2038	1800	7710			5820	1530	2490	2430			1200		**22980**
2039	2010	7920			6810	1860	2490	2430			1200		**24720**
2040	2610	7920			7800	2160	2490	2430			1200	210	**26820**
2041	2610	7920	30		8820	2160	2490	2430			1410	420	**28290**
2042	2610	7920	30		9840	2760	2490	2430			1410	690	**30180**
2043	2610	7920	30		10860	3360	2490	2430			1620	960	**32280**
	2610	**7920**	**30**	**750**	**10860**	**3360**	**2490**	**2430**			**1620**	**960**	**33030**

Capacity Expansion Plan - HG0

Incremental

Year	CT w/ SCR	CC	CC w/ CCS	MPC PPA	Solar	Wind	Battery 4-hr (T1)	Battery 4-hr (T2)	Battery 4-hr (T3)	Battery 4-hr (T4)	Medium Duration Storage	Nuclear	Total
2024	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2025	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2026	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2027	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2028	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2029	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2030	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2031	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2032	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2033	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2034	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2035	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2036	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2037	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2038	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2039	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2040	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2041	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2042	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2043	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED

Cumulative

Year	CT w/ SCR	CC	CC w/ CCS	MPC PPA	Solar	Wind	Battery 4-hr (T1)	Battery 4-hr (T2)	Battery 4-hr (T3)	Battery 4-hr (T4)	Medium Duration Storage	Nuclear	Total
2024	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2025	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2026	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2027	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2028	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2029	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2030	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2031	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2032	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2033	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2034	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2035	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2036	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2037	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2038	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2039	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2040	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2041	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2042	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2043	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED

Capacity Expansion Plan - HG0 (GPC Only)

Incremental

Year	CT w/ SCR	CC	CC w/ CCS	MPC PPA	Solar	Wind	Battery 4-hr (T1)	Battery 4-hr (T2)	Battery 4-hr (T3)	Battery 4-hr (T4)	Medium Duration Storage	Nuclear	Total
2024													
2025													
2026													
2027				750									**750**
2028					750		600						**1350**
2029							2040	600					**2640**
2030		1080			750								**1830**
2031		2400			180								**2580**
2032		300			180	600							**1080**
2033		210			570	390							**1170**
2034		420			570			210					**1200**
2035		900			600	600		300				300	**2700**
2036	300	2400			990	600		1050			300	300	**5940**
2037					990	510						210	**1710**
2038					990	600		420	210			300	**2520**
2039		210			990	300						210	**1710**
2040					990	600			300			300	**2190**
2041					1020				210				**1230**
2042					1020	600						270	**1890**
2043	240				1020	600						210	**2070**
	540	**7920**		**750**	**11610**	**5400**	**2640**	**2580**	**720**		**300**	**2100**	**34560**

Cumulative

Year	CT w/ SCR	CC	CC w/ CCS	MPC PPA	Solar	Wind	Battery 4-hr (T1)	Battery 4-hr (T2)	Battery 4-hr (T3)	Battery 4-hr (T4)	Medium Duration Storage	Nuclear	Total
2024													
2025													
2026													
2027				750									**750**
2028				750	750		600						**2100**
2029					750		2640	600					**3990**
2030		1080			1500		2640	600					**5820**
2031		3480			1680		2640	600					**8400**
2032		3780			1860	600	2640	600					**9480**
2033		3990			2430	990	2640	600					**10650**
2034		4410			3000	990	2640	810					**11850**
2035		5310			3600	1590	2640	1110				300	**14550**
2036	300	7710			4590	2190	2640	2160			300	600	**20490**
2037	300	7710			5580	2700	2640	2160			300	810	**22200**
2038	300	7710			6570	3300	2640	2580	210		300	1110	**24720**
2039	300	7920			7560	3600	2640	2580	210		300	1320	**26430**
2040	300	7920			8550	4200	2640	2580	510		300	1620	**28620**
2041	300	7920			9570	4200	2640	2580	720		300	1620	**29850**
2042	300	7920			10590	4800	2640	2580	720		300	1890	**31740**
2043	540	7920			11610	5400	2640	2580	720		300	2100	**33810**
	540	**7920**		**750**	**11610**	**5400**	**2640**	**2580**	**720**		**300**	**2100**	**34560**

Capacity Expansion Plan - MG20

Incremental

Year	CT w/ SCR	CC	CC w/ CCS	MPC PPA	Solar	Wind	Battery 4-hr (T1)	Battery 4-hr (T2)	Battery 4-hr (T3)	Battery 4-hr (T4)	Medium Duration Storage	Nuclear	Total
2024	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2025	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2026	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2027	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2028	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2029	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2030	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2031	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2032	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2033	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2034	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2035	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2036	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2037	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2038	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2039	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2040	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2041	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2042	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2043	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED

Cumulative

Year	CT w/ SCR	CC	CC w/ CCS	MPC PPA	Solar	Wind	Battery 4-hr (T1)	Battery 4-hr (T2)	Battery 4-hr (T3)	Battery 4-hr (T4)	Medium Duration Storage	Nuclear	Total
2024	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2025	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2026	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2027	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2028	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2029	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2030	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2031	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2032	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2033	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2034	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2035	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2036	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2037	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2038	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2039	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2040	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2041	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2042	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2043	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED

Capacity Expansion Plan - MG20 (GPC Only)

Incremental

Year	CT w/ SCR	CC	CC w/ CCS	MPC PPA	Solar	Wind	Battery 4-hr (T1)	Battery 4-hr (T2)	Battery 4-hr (T3)	Battery 4-hr (T4)	Medium Duration Storage	Nuclear	Total
2024													
2025													
2026													
2027				750			600						**1350**
2028					750		1200						**1950**
2029	1200						780						**1980**
2030		1080			750								**1830**
2031		2700			180								**2880**
2032					180	600							**780**
2033		210			570	450							**1230**
2034					570	180							**750**
2035			1800		600	600						210	**3210**
2036			2100		990	600		2340				300	**6330**
2037					990	600		210				270	**2070**
2038					990	600			750			300	**2640**
2039					990	390			210			210	**1800**
2040					990	600			570			300	**2460**
2041					990				810	210	30		**2040**
2042					990	600						270	**1860**
2043					1020	540				210		270	**2040**
	1200	**3990**	**3900**	**750**	**11550**	**5760**	**2580**	**2550**	**2340**	**420**	**30**	**2130**	**37200**

Cumulative

Year	CT w/ SCR	CC	CC w/ CCS	MPC PPA	Solar	Wind	Battery 4-hr (T1)	Battery 4-hr (T2)	Battery 4-hr (T3)	Battery 4-hr (T4)	Medium Duration Storage	Nuclear	Total
2024													
2025													
2026													
2027				750			600						**1350**
2028				750	750		1800						**3300**
2029	1200				750		2580						**4530**
2030	1200	1080			1500		2580						**6360**
2031	1200	3780			1680		2580						**9240**
2032	1200	3780			1860	600	2580						**10020**
2033	1200	3990			2430	1050	2580						**11250**
2034	1200	3990			3000	1230	2580						**12000**
2035	1200	3990	1800		3600	1830	2580					210	**15210**
2036	1200	3990	3900		4590	2430	2580	2340				510	**21540**
2037	1200	3990	3900		5580	3030	2580	2550				780	**23610**
2038	1200	3990	3900		6570	3630	2580	2550	750			1080	**26250**
2039	1200	3990	3900		7560	4020	2580	2550	960			1290	**28050**
2040	1200	3990	3900		8550	4620	2580	2550	1530			1590	**30510**
2041	1200	3990	3900		9540	4620	2580	2550	2340	210	30	1590	**32550**
2042	1200	3990	3900		10530	5220	2580	2550	2340	210	30	1860	**34410**
2043	1200	3990	3900		11550	5760	2580	2550	2340	420	30	2130	**36450**
	1200	**3990**	**3900**	**750**	**11550**	**5760**	**2580**	**2550**	**2340**	**420**	**30**	**2130**	**37200**

Capacity Expansion Plan - MG50

Incremental

Year	CT w/ SCR	CC	CC w/ CCS	MPC PPA	Solar	Wind	Battery 4-hr (T1)	Battery 4-hr (T2)	Battery 4-hr (T3)	Battery 4-hr (T4)	Medium Duration Storage	Nuclear	Total
2024	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2025	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2026	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2027	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2028	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2029	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2030	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2031	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2032	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2033	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2034	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2035	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2036	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2037	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2038	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2039	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2040	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2041	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2042	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2043	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED

Cumulative

Year	CT w/ SCR	CC	CC w/ CCS	MPC PPA	Solar	Wind	Battery 4-hr (T1)	Battery 4-hr (T2)	Battery 4-hr (T3)	Battery 4-hr (T4)	Medium Duration Storage	Nuclear	Total
2024	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2025	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2026	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2027	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2028	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2029	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2030	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2031	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2032	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2033	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2034	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2035	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2036	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2037	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2038	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2039	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2040	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2041	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2042	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2043	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED

Capacity Expansion Plan - MG50 (GPC Only)

Incremental

Year	CT w/ SCR	CC	CC w/ CCS	MPC PPA	Solar	Wind	Battery 4-hr (T1)	Battery 4-hr (T2)	Battery 4-hr (T3)	Battery 4-hr (T4)	Medium Duration Storage	Nuclear	Total
2024													
2025													
2026													
2027				750			300						**1050**
2028	300				750		900						**1950**
2029	600						1290	300					**2190**
2030	600	660			750			390					**2400**
2031					180			1800					**1980**
2032	300				180	600							**1080**
2033					570	600		300					**1470**
2034			780		570	600							**1950**
2035			2490		600	600						210	**3900**
2036			3600		990	600			420			300	**5910**
2037					990	600			420			300	**2310**
2038					990	600			1320			300	**3210**
2039			210		990	270						210	**1680**
2040			750		990	600						210	**2550**
2041					990					90			**1080**
2042					990	480				210		210	**1890**
2043	210				990	390				390		210	**2190**
	2010	**660**	**7830**	**750**	**11520**	**5940**	**2490**	**2790**	**2160**	**690**		**1950**	**38790**

Cumulative

Year	CT w/ SCR	CC	CC w/ CCS	MPC PPA	Solar	Wind	Battery 4-hr (T1)	Battery 4-hr (T2)	Battery 4-hr (T3)	Battery 4-hr (T4)	Medium Duration Storage	Nuclear	Total
2024													
2025													
2026													
2027				750			300						**1050**
2028	300			750	750		1200						**3000**
2029	900				750		2490	300					**4440**
2030	1500	660			1500		2490	690					**6840**
2031	1500	660			1680		2490	2490					**8820**
2032	1800	660			1860	600	2490	2490					**9900**
2033	1800	660			2430	1200	2490	2790					**11370**
2034	1800	660	780		3000	1800	2490	2790					**13320**
2035	1800	660	3270		3600	2400	2490	2790				210	**17220**
2036	1800	660	6870		4590	3000	2490	2790	420			510	**23130**
2037	1800	660	6870		5580	3600	2490	2790	840			810	**25440**
2038	1800	660	6870		6570	4200	2490	2790	2160			1110	**28650**
2039	1800	660	7080		7560	4470	2490	2790	2160			1320	**30330**
2040	1800	660	7830		8550	5070	2490	2790	2160			1530	**32880**
2041	1800	660	7830		9540	5070	2490	2790	2160	90		1530	**33960**
2042	1800	660	7830		10530	5550	2490	2790	2160	300		1740	**35850**
2043	2010	660	7830		11520	5940	2490	2790	2160	690		1950	**38040**
	2010	**660**	**7830**	**750**	**11520**	**5940**	**2490**	**2790**	**2160**	**690**		**1950**	**38790**

Capacity Expansion Plan - EL

Incremental

Year	CT w/ SCR	CC	CC w/ CCS	MPC PPA	Solar	Wind	Battery 4-hr (T1)	Battery 4-hr (T2)	Battery 4-hr (T3)	Battery 4-hr (T4)	Medium Duration Storage	Nuclear	Total
2024	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2025	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2026	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2027	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2028	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2029	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2030	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2031	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2032	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2033	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2034	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2035	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2036	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2037	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2038	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2039	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2040	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2041	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2042	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2043	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED

Cumulative

Year	CT w/ SCR	CC	CC w/ CCS	MPC PPA	Solar	Wind	Battery 4-hr (T1)	Battery 4-hr (T2)	Battery 4-hr (T3)	Battery 4-hr (T4)	Medium Duration Storage	Nuclear	Total
2024	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2025	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2026	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2027	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2028	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2029	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2030	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2031	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2032	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2033	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2034	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2035	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2036	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2037	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2038	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2039	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2040	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2041	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2042	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2043	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED

Capacity Expansion Plan - EL (GPC Only)

Incremental

Year	CT w/ SCR	CC	CC w/ CCS	MPC PPA	Solar	Wind	Battery 4-hr (T1)	Battery 4-hr (T2)	Battery 4-hr (T3)	Battery 4-hr (T4)	Medium Duration Storage	Nuclear	Total
2024													
2025													
2026													
2027				750	900		300						**1950**
2028	300				930		300						**1530**
2029	300				930		1890	600					**3720**
2030		600			960			540					**2100**
2031	300				960			1800	1200				**4260**
2032					960	600			300				**1860**
2033					960	600			420				**1980**
2034			630		960	300							**1890**
2035			2490		990	600			210			210	**4500**
2036			3870		990	600			420	630		210	**6720**
2037					990	600				630		300	**2520**
2038					990	600				1080		300	**2970**
2039			210		990	270						210	**1680**
2040			750		990	600						210	**2550**
2041					990								**990**
2042			270		990							210	**1470**
2043	210				990	390				600		210	**2400**
	1110	**600**	**8220**	**750**	**16470**	**5160**	**2490**	**2940**	**2550**	**2940**		**1860**	**45090**

Cumulative

Year	CT w/ SCR	CC	CC w/ CCS	MPC PPA	Solar	Wind	Battery 4-hr (T1)	Battery 4-hr (T2)	Battery 4-hr (T3)	Battery 4-hr (T4)	Medium Duration Storage	Nuclear	Total
2024													
2025													
2026													
2027				750	900		300						**1950**
2028	300			750	1830		600						**3480**
2029	600				2760		2490	600					**6450**
2030	600	600			3720		2490	1140					**8550**
2031	900	600			4680		2490	2940	1200				**12810**
2032	900	600			5640	600	2490	2940	1500				**14670**
2033	900	600			6600	1200	2490	2940	1920				**16650**
2034	900	600	630		7560	1500	2490	2940	1920				**18540**
2035	900	600	3120		8550	2100	2490	2940	2130			210	**23040**
2036	900	600	6990		9540	2700	2490	2940	2550	630		420	**29760**
2037	900	600	6990		10530	3300	2490	2940	2550	1260		720	**32280**
2038	900	600	6990		11520	3900	2490	2940	2550	2340		1020	**35250**
2039	900	600	7200		12510	4170	2490	2940	2550	2340		1230	**36930**
2040	900	600	7950		13500	4770	2490	2940	2550	2340		1440	**39480**
2041	900	600	7950		14490	4770	2490	2940	2550	2340		1440	**40470**
2042	900	600	8220		15480	4770	2490	2940	2550	2340		1650	**41940**
2043	1110	600	8220		16470	5160	2490	2940	2550	2940		1860	**44340**
	1110	**600**	**8220**	**750**	**16470**	**5160**	**2490**	**2940**	**2550**	**2940**		**1860**	**45090**

Total System Costs - Planning Horizon 2024-2058

Scenario		NPV_{2024} ($000)
MG0	$	126,133,088.17
LG0	$	119,084,136.42
HG0	$	141,797,422.99
MG20	$	146,794,448.32
MG50	$	181,546,225.44
EL	$	199,803,274.91

Southern Company

2023 Integrated Resource Plan Update

Resource Mix Study

Supplemental Update

December 2023

SUMMARY

The primary objective of this study is to provide information regarding the development of an optimal least-cost resource mix or generic expansion plan. The generic expansion plan was selected to minimize revenue requirements while complying with reliability criteria, environmental laws, and regulations, considering risk and flexibility. This study provides an informative roadmap for long-term decisions. The results of this Resource Mix Study do not represent commitments but instead represent a generic expansion plan used for planning and to support analyses. Under the framework established in the state of Georgia, when a capacity need is identified through an Integrated Resource Plan ("IRP"), Georgia Power Company ("Georgia Power" or the "Company") will meet such identified need in accordance with the Georgia Public Service Commission ("Commission") rules and will utilize Georgia Power specific information, as appropriate.

This report summarizes the remaining results of the 2023 IRP Update Resource Mix Study, including all scenarios related to uncertainty around long-term fuel cost, carbon pressure, technology cost and performance, and future electricity consumption. A summary of the six outlooks provided are shown in Table 1. The moderate gas, low greenhouse gas pressure view ("MG0") was provided in the initial filing submitted to the Commission on October 27, 2023. The remaining five scenarios will be addressed in this supplemental update. For more information on the assumptions that are included in the Resource Mix Study, please refer to the 2023 IRP Update Technical Appendix Resource Mix Study.

Table 1: Planning Scenarios

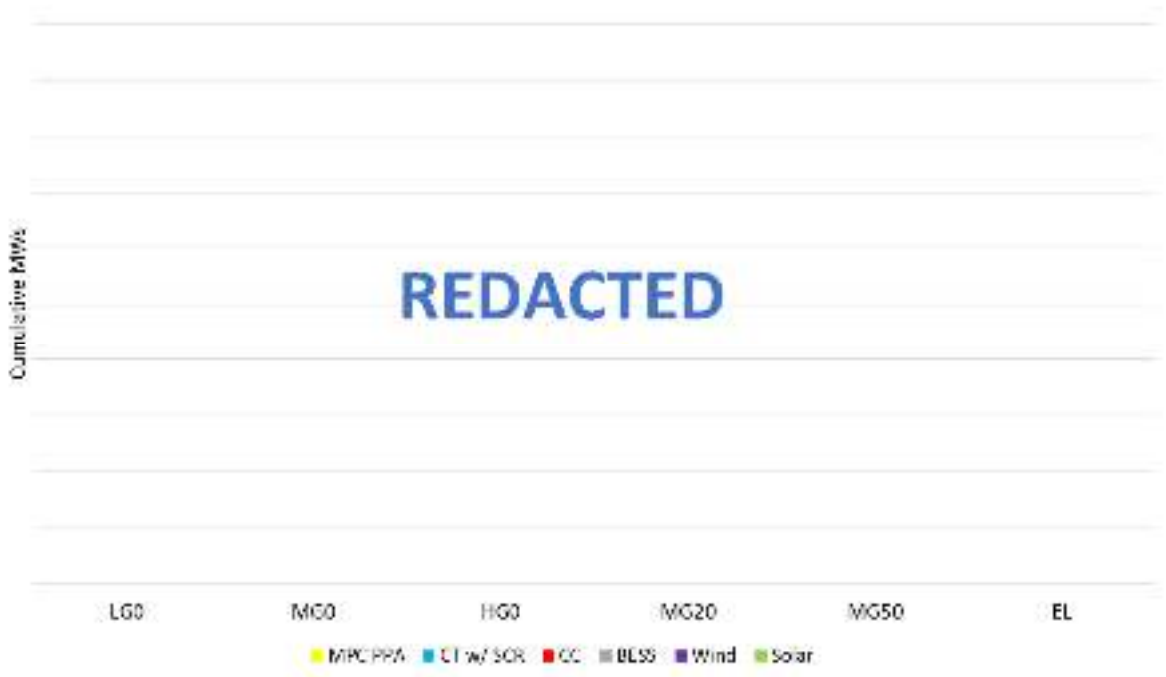
Scenario	GHG pressure view	Technology view	Load view	Fuel view	Label
1	Lower	Tech Portfolio	2023 IRP Update	Lower	LG0
2	Lower	Tech Portfolio	2023 IRP Update	Moderate	MG0
3	Lower	Tech Portfolio	2023 IRP Update + HG0 delta	Higher	HG0
4	Moderate ($20)	IRA 2045	Alt 1	Moderate	MG20
5	Higher ($50)	IRA 2035	Alt 2	Moderate	MG50
6	Emissions Limit	IRA 2035	Alt 2	Moderate	EL

SCENARIO RESULTS

The results of the Resource Mix Study Supplemental Update provide an economically optimum resource addition schedule for the retail operating companies, based on various futures. These results provide an indicative roadmap for long-term decisions based on uncertainties around the future of natural gas prices, environmental pressures, cost and performance of future generating technologies, and future load growth.

The results of the scenario analysis have been broken into two sections, near-term and long-term optimum resource mix. Figure 1, below, shows the cumulative build by 2033 and details the near-term optimal capacity and energy expansion plan for all six scenarios. Based on the scenario results, it can be concluded that additional generation capacity requirements may involve a mixture of natural gas combined cycle, dual-fuel combustion turbine with SCR, solar photovoltaic, wind, battery storage, and a market option, such as the Mississippi Power Company PPA, to help address near term capacity needs.

Figure 1: 2023 IRP Update Expansion Plans – Cumulative Build by 2033

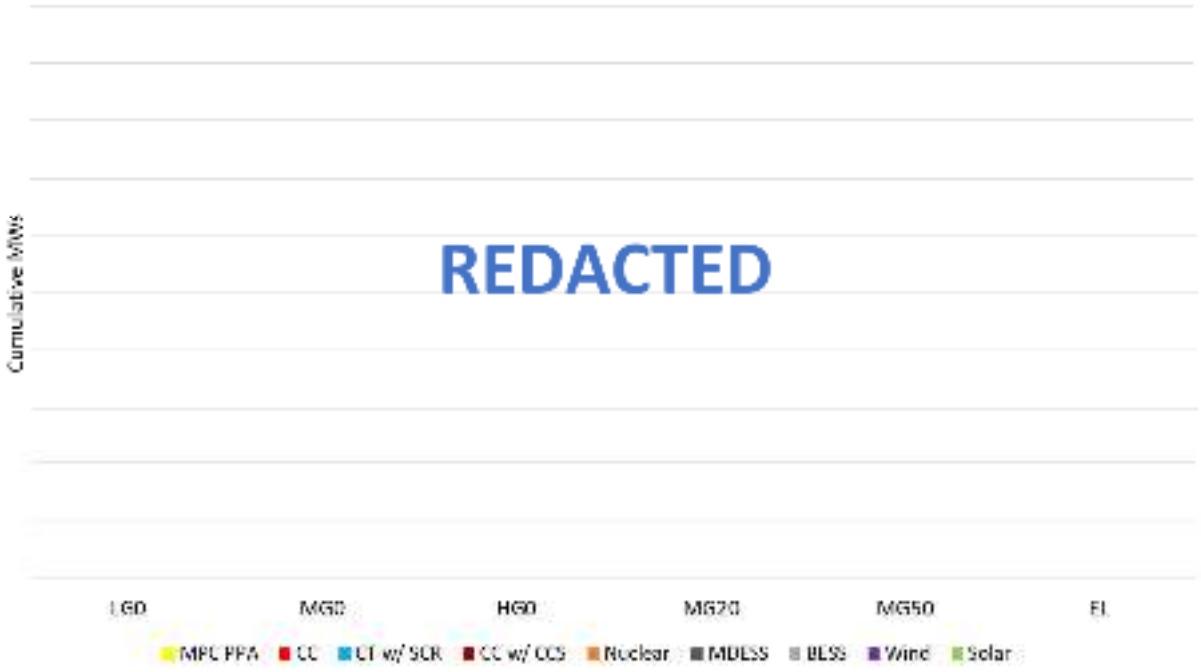


Based on the results of the study, immediate capacity needs are optimally met with a combination of storage, dual-fuel CTs with SCR, and market purchases. In five of six scenarios, storage is selected as early as 2027 and dual-fuel CTs with SCR are selected as early as 2028. All six scenarios include a mix of thermal

units, renewables, storage, and market purchases regardless of variations in input assumptions that make up the scenarios.

A long-term look at the scenario analysis can draw similar conclusions to those reached in the near-term. Figure 2, below, shows the cumulative build by 2043 for all six scenarios. From the scenario analysis, it can be concluded that in addition to the generation technologies selected in the near-term, a mix of nuclear, medium duration storage, and natural gas combined cycle with carbon capture and sequestration may be needed to meet additional generation capacity requirements in the long-term based on various futures.

Figure 2: 2023 IRP Update Expansion Plans – Cumulative Build by 2043



Please see the accompanying Capacity Expansion Plans Supplemental file for a summary of results for all scenarios.

CERTIFICATE OF SERVICE

I hereby certify that I have this day served a copy of the within and foregoing GEORGIA POWER COMPANY'S SUPPLEMENTAL FILING IN DOCKET NO. 55378 upon all parties listed below via electronic service or by hand delivery and addressed as follows:

Sallie Tanner Executive Secretary Georgia Public Service Commission 244 Washington Street, SW Atlanta, GA 30334 stanner@psc.ga.gov	Preston Thomas Georgia Public Service Commission 244 Washington Street, SW Atlanta, GA 30334 pthomas@psc.state.ga.us
Charles B. Jones, III Lloyd Avram Georgia Association of Manufacturers The Hurt Building 50 Hurt Plaza, Suite 1620 Atlanta, Georgia 30303 (404) 688-0555 cjones@gamfg.org lavram@gamfg.org	Jeffry C. Pollock J. Pollock Incorporated 14323 South Outer 40 Road, Suite 206N Town and Country, Missouri 63017-5734 (314) 878-5814 (314) 878-7339 (fax) jcp@jpollockinc.com
Scott F. Dunbar Keyes & Fox LLP 1580 Lincoln Street, Suite 1105 Denver, CO 80203 sdunbar@keyesfox.com	Alicia Zaloga Keyes & Fox LLP 1155 Kildaire Farm Road, Suite 202-203 Cary, NC 27511 azaloga@keyesfox.com
Bryan Jacob Southern Alliance for Clean Energy 1455 Hampton Hill Drive Alpharetta, GA 30022 bryan@cleanenergy.org	Jennifer Whitfield Robert Sherrier Southern Environmental Law Center Ten 10th Street Suite 1050 Atlanta, GA 30309 jwhitfield@selcga.org bsherrier@selcga.org
Kimberly ("Kasey") A. Sturm Weissman PC One Alliance Center, Fourth Floor 3500 Lenox Road Atlanta, Georgia 30326 kaseys@weissman.law	Peter J. Andrews Metropolitan Atlanta Rapid Transit Authority 2424 Piedmont Road, NE Atlanta, GA 30324 pandrews@itsmarta.com

This 4th day of December 2023.



Allison W. Pryor
Attorney for Georgia Power Company

TROUTMAN PEPPER HAMILTON SANDERS LLP
Bank of America Plaza
600 Peachtree St., N.E.
Suite 3000
Atlanta, Georgia 30308-2216
(404) 885-3000

GPC EXHIBIT 6

Bin 10230
241 Ralph McGill Boulevard, NE
Atlanta, GA 30308-3374

PUBLIC DISCLOSURE

December 7, 2023

Ms. Sallie Tanner
Executive Secretary
Georgia Public Service Commission
244 Washington Street, SW
Atlanta, GA 30334-5701

RE: Georgia Power Company's 2023 Integrated Resource Plan Update; Docket No. 55378

Dear Ms. Tanner:

Georgia Power Company ("Georgia Power" or the "Company") files this errata to its December 4, 2023 Supplemental Filing to the 2023 IRP Update in Docket No. 55378. The Company identified an error within the Resource Mix Study Supplemental Update whereby Georgia Power's capacity and energy allocation based on the system generic expansion plan was understated. The revision to the file "TS Capacity Expansion Plans Supplemental" is attached hereto. Notably, this change only impacts Georgia Power allocations and has no impact on the Company's production cost modeling runs and results or the economic analyses supporting the resources requested within the Company's 2023 IRP Update that have already been completed and filed.

This filing contains certain information that is being filed under the Commission's trade secret rules as explained in the enclosed basis for assertion. Therefore, in addition to the electronic trade secret file, an electronic version of the redacted file is enclosed for public disclosure.

If you have any questions, please contact Cheryl Johnson at 404-506-6837.

Sincerely,

/s/ Kelley M. Balkcom

Kelley M. Balkcom
Director, Regulatory Affairs
mmcclosk@southernco.com

Enclosure

BEFORE THE GEORGIA PUBLIC SERVICE COMMISSION

GEORGIA POWER COMPANY
DOCKET NO. 55378

2023 IRP UPDATE SUPPLEMENTAL FILING ERRATA

BASIS FOR THE ASSERTION THAT THE INFORMATION SUBMITTED IS A TRADE SECRET

As part of Georgia Power Company's 2023 Integrated Resource Plan Update filed in Docket No. 55378 ("2023 IRP Update"), Georgia Power Company ("Georgia Power" or the "Company") submits to the Georgia Public Service Commission its Errata to the 2023 IRP Update Supplemental Filing ("Supplemental Filing Errata"). In the Supplemental Filing Errata, the Company has provided certain information regarding the Company's proprietary planning processes, financial data, technology screening assumptions, generic technology and resource cost information, specific resource, technology and avoided cost information, economic analyses, load and energy forecast data assumptions, and other data (the "Information"). All of such information constitutes trade secret information of Southern Company, Georgia Power, and its affiliates and is therefore protected from public disclosure under Commission Rule 515-3-1-.11.

The Information derives economic value from not being generally known to, and not being readily ascertainable by proper means by other persons who can obtain economic value from its disclosure or use. Specifically, the trade secret portions of the Information contained herein include competitively sensitive pricing and operational capability data, including project development timelines where applicable, specific to the resources under contract within each power purchase agreement or proposed to be developed. If the Information were made public, competitors, bidders, and suppliers could use the Information to unfairly manipulate the request for proposals process and competitive market to structure future bids and set an artificial price floor to arbitrarily increase prices to the detriment of the Company and its customers. Public dissemination of the Information would undermine Georgia Power's ability to negotiate the best price and contract terms and could harm the Company's ability to secure the best cost bids and resources for the benefit of customers. In addition, the terms of the power purchase agreements themselves provides for the confidentiality and protection of the Information. Compromising the confidentiality of such Information could harm Georgia Power in future PPA negotiations, as counterparties may fear compelled disclosure of key contractual terms. Lastly, the Company's competitors are not required to reveal or publish similar information.

The trade secret portions of the Information also contain competitively sensitive cost information related to available technology options, processes and data used by Georgia Power in analyzing resource addition schedules, financial data used in the Company's resource analyses, and other confidential details including data supporting resource economic evaluations. Public dissemination of the trade secret portions of the Information would allow Georgia Power's competitors and suppliers to have access to such processes and strategies and thereby gain an unfair competitive advantage in the marketplace. Competitors would obtain an unfair advantage because they are not required to reveal similar information and can utilize such trade secret portions of the

Information to manipulate pricing and timing of supply to the disadvantage of Georgia Power. Competitors would also unfairly benefit in having access and insight into the Company's planning processes and methodologies. This competitive advantage for the Company's suppliers and competitors would mean that Georgia Power will potentially pay higher prices to suppliers, ultimately harming Georgia Power and its customers.

The Information is subject to substantial procedures to maintain its secrecy. Only select Georgia Power and Southern Company Services personnel are granted access to the Information. Those personnel receive access only on a "need to know" basis. Parties outside the Company who have been granted access to the Information, if any, have been required to sign confidentiality agreements with respect to the Information.

Jeffrey R. Grubb, first being duly sworn, deposes and states that he has reviewed the Company's 2023 IRP Update Supplemental Filing Errata and that to the best of his knowledge the specific information designated as trade secret constitute trade secrets in accordance with O.C.G.A. § 10-1-761 (2021).

Jeffrey R. Grubb
Director, Resource Policy & Planning
Georgia Power Company

Subscribed and sworn to before me this 7th day of December, 2023.

Notary Public

My Commission expires:



Capacity Expansion Plan - MG0

Incremental

Year	CT w/ SCR	CC	CC w/ CCS	MPC PPA	Solar	Wind	Battery 4-hr (T1)	Battery 4-hr (T2)	Battery 4-hr (T3)	Battery 4-hr (T4)	Medium Duration Storage	Nuclear	Total
2024	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2025	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2026	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2027	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2028	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2029	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2030	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2031	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2032	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2033	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2034	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2035	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2036	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2037	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2038	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2039	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2040	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2041	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2042	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2043	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED

Cumulative

Year	CT w/ SCR	CC	CC w/ CCS	MPC PPA	Solar	Wind	Battery 4-hr (T1)	Battery 4-hr (T2)	Battery 4-hr (T3)	Battery 4-hr (T4)	Medium Duration Storage	Nuclear	Total
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2025	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2026	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2027	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2028	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2029	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2030	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2031	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2032	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2033	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2034	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2035	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2036	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2037	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2038	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2039	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2040	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2041	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2042	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2043	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED

Capacity Expansion Plan - MG0 (GPC Only)

Incremental

Year	CT w/ SCR	CC	CC w/ CCS	MPC PPA	Solar	Wind	Battery 4-hr (T1)	Battery 4-hr (T2)	Battery 4-hr (T3)	Battery 4-hr (T4)	Medium Duration Storage	Nuclear	Total
2024													
2025													
2026													
2027				750			900						**1650**
2028	300				750		780						**1830**
2029	1200						780	420					**2400**
2030		900			750								**1650**
2031		2700			180								**2880**
2032		300			180								**480**
2033		210			570	150							**930**
2034		210			570	120							**900**
2035	300	1710			600	600							**3210**
2036	600	1800			990	600		1500				300	**5790**
2037					990	300		210					**1500**
2038					990	600		270				300	**2160**
2039		210			990	300						210	**1710**
2040					990	600			1110			300	**3000**
2041					1020				540				**1560**
2042					1020	300							**1320**
2043					1020	300				300		300	**1920**
	2400	**8040**		**750**	**11610**	**3870**	**2460**	**2400**	**1650**	**300**		**1410**	**34890**

Cumulative

Year	CT w/ SCR	CC	CC w/ CCS	MPC PPA	Solar	Wind	Battery 4-hr (T1)	Battery 4-hr (T2)	Battery 4-hr (T3)	Battery 4-hr (T4)	Medium Duration Storage	Nuclear	Total
2024													
2025													
2026													
2027				750			900						**1650**
2028	300			750	750		1680						**3480**
2029	1500				750		2460	420					**5130**
2030	1500	900			1500		2460	420					**6780**
2031	1500	3600			1680		2460	420					**9660**
2032	1500	3900			1860		2460	420					**10140**
2033	1500	4110			2430	150	2460	420					**11070**
2034	1500	4320			3000	270	2460	420					**11970**
2035	1800	6030			3600	870	2460	420					**15180**
2036	2400	7830			4590	1470	2460	1920				300	**20970**
2037	2400	7830			5580	1770	2460	2130				300	**22470**
2038	2400	7830			6570	2370	2460	2400				600	**24630**
2039	2400	8040			7560	2670	2460	2400				810	**26340**
2040	2400	8040			8550	3270	2460	2400	1110			1110	**29340**
2041	2400	8040			9570	3270	2460	2400	1650			1110	**30900**
2042	2400	8040			10590	3570	2460	2400	1650			1110	**32220**
2043	2400	8040			11610	3870	2460	2400	1650	300		1410	**34140**
	2400	**8040**		**750**	**11610**	**3870**	**2460**	**2400**	**1650**	**300**		**1410**	**34890**

Capacity Expansion Plan - LG0

Incremental

Year	CT w/ SCR	CC	CC w/ CCS	MPC PPA	Solar	Wind	Battery 4-hr (T1)	Battery 4-hr (T2)	Battery 4-hr (T3)	Battery 4-hr (T4)	Medium Duration Storage	Nuclear	Total
2024	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2025	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2026	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2027	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2028	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2029	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2030	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2031	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2032	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
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2034	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2035	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
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2040	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2041	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2042	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2043	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED

Cumulative

Year	CT w/ SCR	CC	CC w/ CCS	MPC PPA	Solar	Wind	Battery 4-hr (T1)	Battery 4-hr (T2)	Battery 4-hr (T3)	Battery 4-hr (T4)	Medium Duration Storage	Nuclear	Total
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2025	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2026	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2027	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2028	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2029	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2030	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2031	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2032	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2033	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
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2035	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2036	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2037	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2038	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2039	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2040	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2041	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2042	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2043	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED

Capacity Expansion Plan - LG0 (GPC Only)

Incremental

Year	CT w/ SCR	CC	CC w/ CCS	MPC PPA	Solar	Wind	Battery 4-hr (T1)	Battery 4-hr (T2)	Battery 4-hr (T3)	Battery 4-hr (T4)	Medium Duration Storage	Nuclear	Total
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2025													
2026													
2027				750			900						**1650**
2028	300						600						**900**
2029	1200						990	420					**2610**
2030		900			750								**1650**
2031		2700			180								**2880**
2032		300			180								**480**
2033		210			570	330							**1110**
2034		300			570								**870**
2035		1800			600	600							**3000**
2036	600	1500			990	600		900			1200		**5790**
2037					990			270					**1260**
2038					990			840					**1830**
2039	210	210			990	300							**1710**
2040	600				990	300						210	**2100**
2041			30		1020						210	210	**1470**
2042					1020	600						270	**1890**
2043					1020	600					210	270	**2100**
	2910	**7920**	**30**	**750**	**10860**	**3330**	**2490**	**2430**			**1620**	**960**	**33300**

Cumulative

Year	CT w/ SCR	CC	CC w/ CCS	MPC PPA	Solar	Wind	Battery 4-hr (T1)	Battery 4-hr (T2)	Battery 4-hr (T3)	Battery 4-hr (T4)	Medium Duration Storage	Nuclear	Total
2024													
2025													
2026													
2027				750			900						**1650**
2028	300			750			1500						**2550**
2029	1500						2490	420					**4410**
2030	1500	900			750		2490	420					**6060**
2031	1500	3600			930		2490	420					**8940**
2032	1500	3900			1110		2490	420					**9420**
2033	1500	4110			1680	330	2490	420					**10530**
2034	1500	4410			2250	330	2490	420					**11400**
2035	1500	6210			2850	930	2490	420					**14400**
2036	2100	7710			3840	1530	2490	1320			1200		**20190**
2037	2100	7710			4830	1530	2490	1590			1200		**21450**
2038	2100	7710			5820	1530	2490	2430			1200		**23280**
2039	2310	7920			6810	1830	2490	2430			1200		**24990**
2040	2910	7920			7800	2130	2490	2430			1200	210	**27090**
2041	2910	7920	30		8820	2130	2490	2430			1410	420	**28560**
2042	2910	7920	30		9840	2730	2490	2430			1410	690	**30450**
2043	2910	7920	30		10860	3330	2490	2430			1620	960	**32550**
	2910	**7920**	**30**	**750**	**10860**	**3330**	**2490**	**2430**			**1620**	**960**	**33300**

Capacity Expansion Plan - HG0

Incremental

Year	CT w/ SCR	CC	CC w/ CCS	MPC PPA	Solar	Wind	Battery 4-hr (T1)	Battery 4-hr (T2)	Battery 4-hr (T3)	Battery 4-hr (T4)	Medium Duration Storage	Nuclear	Total
2024	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2025	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2026	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2027	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2028	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2029	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2030	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2031	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2032	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2033	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2034	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2035	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2036	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2037	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2038	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2039	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2040	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2041	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2042	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2043	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED

Cumulative

Year	CT w/ SCR	CC	CC w/ CCS	MPC PPA	Solar	Wind	Battery 4-hr (T1)	Battery 4-hr (T2)	Battery 4-hr (T3)	Battery 4-hr (T4)	Medium Duration Storage	Nuclear	Total
2024	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2025	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2026	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2027	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2028	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2029	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2030	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2031	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2032	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2033	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2034	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2035	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2036	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2037	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2038	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2039	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2040	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2041	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2042	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2043	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED

Capacity Expansion Plan - HG0 (GPC Only)

Incremental

Year	CT w/ SCR	CC	CC w/ CCS	MPC PPA	Solar	Wind	Battery 4-hr (T1)	Battery 4-hr (T2)	Battery 4-hr (T3)	Battery 4-hr (T4)	Medium Duration Storage	Nuclear	Total
2024													
2025													
2026													
2027				750									**750**
2028					750		600						**1350**
2029							2340	600					**2940**
2030		1050			750								**1800**
2031		2400			180								**2580**
2032		300			180	600							**1080**
2033		210			570	360							**1140**
2034		420			570			210					**1200**
2035		900			600	600		300				300	**2700**
2036	300	2400			990	600		1050			300	300	**5940**
2037					990	510						210	**1710**
2038					990	600		420	210			300	**2520**
2039		210			990	300						210	**1710**
2040					990	600			300			300	**2190**
2041					1020				240				**1260**
2042					1020	600						270	**1890**
2043	240				1020	600						210	**2070**
	540	**7890**		**750**	**11610**	**5370**	**2940**	**2580**	**750**		**300**	**2100**	**34830**

Cumulative

Year	CT w/ SCR	CC	CC w/ CCS	MPC PPA	Solar	Wind	Battery 4-hr (T1)	Battery 4-hr (T2)	Battery 4-hr (T3)	Battery 4-hr (T4)	Medium Duration Storage	Nuclear	Total
2024													
2025													
2026													
2027				750									**750**
2028				750	750		600						**2100**
2029					750		2940	600					**4290**
2030		1050			1500		2940	600					**6090**
2031		3450			1680		2940	600					**8670**
2032		3750			1860	600	2940	600					**9750**
2033		3960			2430	960	2940	600					**10890**
2034		4380			3000	960	2940	810					**12090**
2035		5280			3600	1560	2940	1110				300	**14790**
2036	300	7680			4590	2160	2940	2160			300	600	**20730**
2037	300	7680			5580	2670	2940	2160			300	810	**22440**
2038	300	7680			6570	3270	2940	2580	210		300	1110	**24960**
2039	300	7890			7560	3570	2940	2580	210		300	1320	**26670**
2040	300	7890			8550	4170	2940	2580	510		300	1620	**28860**
2041	300	7890			9570	4170	2940	2580	750		300	1620	**30120**
2042	300	7890			10590	4770	2940	2580	750		300	1890	**32010**
2043	540	7890			11610	5370	2940	2580	750		300	2100	**34080**
	540	**7890**		**750**	**11610**	**5370**	**2940**	**2580**	**750**		**300**	**2100**	**34830**

Capacity Expansion Plan - MG20

Incremental

Year	CT w/ SCR	CC	CC w/ CCS	MPC PPA	Solar	Wind	Battery 4-hr (T1)	Battery 4-hr (T2)	Battery 4-hr (T3)	Battery 4-hr (T4)	Medium Duration Storage	Nuclear	Total
2024	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2025	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2026	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2027	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2028	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2029	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2030	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2031	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2032	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2033	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2034	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2035	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2036	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2037	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2038	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2039	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2040	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2041	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2042	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2043	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED

Cumulative

Year	CT w/ SCR	CC	CC w/ CCS	MPC PPA	Solar	Wind	Battery 4-hr (T1)	Battery 4-hr (T2)	Battery 4-hr (T3)	Battery 4-hr (T4)	Medium Duration Storage	Nuclear	Total
2024	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2025	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2026	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2027	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2028	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2029	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2030	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2031	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2032	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2033	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2034	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2035	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2036	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2037	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2038	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2039	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2040	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2041	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2042	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2043	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED

Capacity Expansion Plan - MG20 (GPC Only)

Incremental

Year	CT w/ SCR	CC	CC w/ CCS	MPC PPA	Solar	Wind	Battery 4-hr (T1)	Battery 4-hr (T2)	Battery 4-hr (T3)	Battery 4-hr (T4)	Medium Duration Storage	Nuclear	Total
2024													
2025													
2026													
2027				750			600						**1350**
2028					750		1200						**1950**
2029	1500						780						**2280**
2030		1080			750								**1830**
2031		2700			180								**2880**
2032					180	600							**780**
2033		210			570	420							**1200**
2034					570	180							**750**
2035			1800		600	600						210	**3210**
2036			2100		990	600		2340				300	**6330**
2037					990	600		210				270	**2070**
2038					990	600			720			300	**2610**
2039					990	360			210			210	**1770**
2040					990	600			540			300	**2430**
2041					990				810	210	60		**2070**
2042					990	600						270	**1860**
2043					1020	540				210		270	**2040**
	1500	**3990**	**3900**	**750**	**11550**	**5700**	**2580**	**2550**	**2280**	**420**	**60**	**2130**	**37410**

Cumulative

Year	CT w/ SCR	CC	CC w/ CCS	MPC PPA	Solar	Wind	Battery 4-hr (T1)	Battery 4-hr (T2)	Battery 4-hr (T3)	Battery 4-hr (T4)	Medium Duration Storage	Nuclear	Total
2024													
2025													
2026													
2027				750			600						**1350**
2028				750	750		1800						**3300**
2029	1500				750		2580						**4830**
2030	1500	1080			1500		2580						**6660**
2031	1500	3780			1680		2580						**9540**
2032	1500	3780			1860	600	2580						**10320**
2033	1500	3990			2430	1020	2580						**11520**
2034	1500	3990			3000	1200	2580						**12270**
2035	1500	3990	1800		3600	1800	2580					210	**15480**
2036	1500	3990	3900		4590	2400	2580	2340				510	**21810**
2037	1500	3990	3900		5580	3000	2580	2550				780	**23880**
2038	1500	3990	3900		6570	3600	2580	2550	720			1080	**26490**
2039	1500	3990	3900		7560	3960	2580	2550	930			1290	**28260**
2040	1500	3990	3900		8550	4560	2580	2550	1470			1590	**30690**
2041	1500	3990	3900		9540	4560	2580	2550	2280	210	60	1590	**32760**
2042	1500	3990	3900		10530	5160	2580	2550	2280	210	60	1860	**34620**
2043	1500	3990	3900		11550	5700	2580	2550	2280	420	60	2130	**36660**
	1500	**3990**	**3900**	**750**	**11550**	**5700**	**2580**	**2550**	**2280**	**420**	**60**	**2130**	**37410**

Capacity Expansion Plan - MG50

Incremental

Year	CT w/ SCR	CC	CC w/ CCS	MPC PPA	Solar	Wind	Battery 4-hr (T1)	Battery 4-hr (T2)	Battery 4-hr (T3)	Battery 4-hr (T4)	Medium Duration Storage	Nuclear	Total
2024	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2025	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2026	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2027	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2028	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2029	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2030	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2031	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2032	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2033	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2034	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2035	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2036	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2037	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2038	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2039	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2040	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2041	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2042	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2043	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED

Cumulative

Year	CT w/ SCR	CC	CC w/ CCS	MPC PPA	Solar	Wind	Battery 4-hr (T1)	Battery 4-hr (T2)	Battery 4-hr (T3)	Battery 4-hr (T4)	Medium Duration Storage	Nuclear	Total
2024	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2025	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2026	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2027	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2028	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2029	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2030	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2031	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2032	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2033	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2034	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2035	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2036	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2037	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2038	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2039	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2040	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2041	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2042	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2043	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED

Capacity Expansion Plan - MG50 (GPC Only)

Incremental

Year	CT w/ SCR	CC	CC w/ CCS	MPC PPA	Solar	Wind	Battery 4-hr (T1)	Battery 4-hr (T2)	Battery 4-hr (T3)	Battery 4-hr (T4)	Medium Duration Storage	Nuclear	Total
2024													
2025													
2026													
2027				750			300						**1050**
2028	300				750		900						**1950**
2029	600						1590	510					**2700**
2030	600	900			750			390					**2640**
2031					180			1800					**1980**
2032	300				180	600							**1080**
2033					570	600		300					**1470**
2034			750		570	600							**1920**
2035			2490		600	600						210	**3900**
2036			3600		990	600			420			300	**5910**
2037					990	600			420			300	**2310**
2038					990	600			1320			300	**3210**
2039			210		990	300						210	**1710**
2040			750		990	600						210	**2550**
2041					990					90			**1080**
2042					990	450				210		210	**1860**
2043	210				990	390				390		210	**2190**
	2010	**900**	**7800**	**750**	**11520**	**5940**	**2790**	**3000**	**2160**	**690**		**1950**	**39510**

Cumulative

Year	CT w/ SCR	CC	CC w/ CCS	MPC PPA	Solar	Wind	Battery 4-hr (T1)	Battery 4-hr (T2)	Battery 4-hr (T3)	Battery 4-hr (T4)	Medium Duration Storage	Nuclear	Total
2024													
2025													
2026													
2027				750			300						**1050**
2028	300			750	750		1200						**3000**
2029	900				750		2790	510					**4950**
2030	1500	900			1500		2790	900					**7590**
2031	1500	900			1680		2790	2700					**9570**
2032	1800	900			1860	600	2790	2700					**10650**
2033	1800	900			2430	1200	2790	3000					**12120**
2034	1800	900	750		3000	1800	2790	3000					**14040**
2035	1800	900	3240		3600	2400	2790	3000				210	**17940**
2036	1800	900	6840		4590	3000	2790	3000	420			510	**23850**
2037	1800	900	6840		5580	3600	2790	3000	840			810	**26160**
2038	1800	900	6840		6570	4200	2790	3000	2160			1110	**29370**
2039	1800	900	7050		7560	4500	2790	3000	2160			1320	**31080**
2040	1800	900	7800		8550	5100	2790	3000	2160			1530	**33630**
2041	1800	900	7800		9540	5100	2790	3000	2160	90		1530	**34710**
2042	1800	900	7800		10530	5550	2790	3000	2160	300		1740	**36570**
2043	2010	900	7800		11520	5940	2790	3000	2160	690		1950	**38760**
	2010	**900**	**7800**	**750**	**11520**	**5940**	**2790**	**3000**	**2160**	**690**		**1950**	**39510**

Capacity Expansion Plan - EL

Incremental

Year	CT w/ SCR	CC	CC w/ CCS	MPC PPA	Solar	Wind	Battery 4-hr (T1)	Battery 4-hr (T2)	Battery 4-hr (T3)	Battery 4-hr (T4)	Medium Duration Storage	Nuclear	Total
2024	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2025	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2026	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2027	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2028	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2029	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2030	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2031	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2032	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2033	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2034	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2035	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2036	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2037	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2038	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2039	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2040	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2041	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2042	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2043	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED

Cumulative

Year	CT w/ SCR	CC	CC w/ CCS	MPC PPA	Solar	Wind	Battery 4-hr (T1)	Battery 4-hr (T2)	Battery 4-hr (T3)	Battery 4-hr (T4)	Medium Duration Storage	Nuclear	Total
2024	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2025	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2026	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2027	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2028	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2029	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2030	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2031	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2032	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2033	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2034	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2035	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2036	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2037	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2038	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2039	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2040	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2041	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2042	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2043	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED

Capacity Expansion Plan - EL (GPC Only)

Incremental

Year	CT w/ SCR	CC	CC w/ CCS	MPC PPA	Solar	Wind	Battery 4-hr (T1)	Battery 4-hr (T2)	Battery 4-hr (T3)	Battery 4-hr (T4)	Medium Duration Storage	Nuclear	Total
2024													
2025													
2026													
2027				750	900		300						**1950**
2028	300				930		300						**1530**
2029	300				930		2190	600					**4020**
2030		600			960			510					**2070**
2031	300				960			1800	1200				**4260**
2032					960	600			300				**1860**
2033					960	600			420				**1980**
2034			630		960	300							**1890**
2035			2490		990	600			210			210	**4500**
2036			3870		990	600			420	630		210	**6720**
2037					990	600				630		300	**2520**
2038					990	600				1080		300	**2970**
2039			210		990	300						210	**1710**
2040			750		990	600						210	**2550**
2041					990								**990**
2042			270		990							210	**1470**
2043	210				990	360				600		210	**2370**
	1110	**600**	**8220**	**750**	**16470**	**5160**	**2790**	**2910**	**2550**	**2940**		**1860**	**45360**

Cumulative

Year	CT w/ SCR	CC	CC w/ CCS	MPC PPA	Solar	Wind	Battery 4-hr (T1)	Battery 4-hr (T2)	Battery 4-hr (T3)	Battery 4-hr (T4)	Medium Duration Storage	Nuclear	Total
2024													
2025													
2026													
2027				750	900		300						**1950**
2028	300			750	1830		600						**3480**
2029	600				2760		2790	600					**6750**
2030	600	600			3720		2790	1110					**8820**
2031	900	600			4680		2790	2910	1200				**13080**
2032	900	600			5640	600	2790	2910	1500				**14940**
2033	900	600			6600	1200	2790	2910	1920				**16920**
2034	900	600	630		7560	1500	2790	2910	1920				**18810**
2035	900	600	3120		8550	2100	2790	2910	2130			210	**23310**
2036	900	600	6990		9540	2700	2790	2910	2550	630		420	**30030**
2037	900	600	6990		10530	3300	2790	2910	2550	1260		720	**32550**
2038	900	600	6990		11520	3900	2790	2910	2550	2340		1020	**35520**
2039	900	600	7200		12510	4200	2790	2910	2550	2340		1230	**37230**
2040	900	600	7950		13500	4800	2790	2910	2550	2340		1440	**39780**
2041	900	600	7950		14490	4800	2790	2910	2550	2340		1440	**40770**
2042	900	600	8220		15480	4800	2790	2910	2550	2340		1650	**42240**
2043	1110	600	8220		16470	5160	2790	2910	2550	2940		1860	**44610**
	1110	**600**	**8220**	**750**	**16470**	**5160**	**2790**	**2910**	**2550**	**2940**		**1860**	**45360**

Total System Costs - Planning Horizon 2024-2058

Scenario		NPV_{2024} ($000)
MG0	$	126,133,088.17
LG0	$	119,084,136.42
HG0	$	141,797,422.99
MG20	$	146,794,448.32
MG50	$	181,546,225.44
EL	$	199,803,274.91

CERTIFICATE OF SERVICE

I hereby certify that I have this day served a copy of the within and foregoing GEORGIA POWER COMPANY'S ERRATA TO THE SUPPLEMENTAL FILING OF DECEMBER 4, 2023 IN DOCKET NO. 55378 upon all parties listed below via electronic service or by hand delivery and addressed as follows:

Sallie Tanner Executive Secretary Georgia Public Service Commission 244 Washington Street, SW Atlanta, GA 30334 stanner@psc.ga.gov	Preston Thomas Georgia Public Service Commission 244 Washington Street, SW Atlanta, GA 30334 pthomas@psc.state.ga.us
Charles B. Jones, III Lloyd Avram Georgia Association of Manufacturers The Hurt Building 50 Hurt Plaza, Suite 1620 Atlanta, Georgia 30303 (404) 688-0555 cjones@gamfg.org lavram@gamfg.org	Jeffry C. Pollock J. Pollock Incorporated 14323 South Outer 40 Road, Suite 206N Town and Country, Missouri 63017-5734 (314) 878-5814 (314) 878-7339 (fax) jcp@jpollockinc.com
Scott F. Dunbar Keyes & Fox LLP 1580 Lincoln Street, Suite 1105 Denver, CO 80203 sdunbar@keyesfox.com	Alicia Zaloga Keyes & Fox LLP 1155 Kildaire Farm Road, Suite 202-203 Cary, NC 27511 azaloga@keyesfox.com
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Kimberly ("Kasey") A. Sturm Weissman PC One Alliance Center, Fourth Floor 3500 Lenox Road Atlanta, Georgia 30326 kaseys@weissman.law	Peter J. Andrews Metropolitan Atlanta Rapid Transit Authority 2424 Piedmont Road, NE Atlanta, GA 30324 pandrews@itsmarta.com

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Dorothy E. Jaffe Sierra Club 50 F Street, NW, 8th Floor Washington, D.C. 20001 dori.jaffe@sierraclub.org	Zachary M. Fabish Sierra Club 50 F Street, NW, 8th Floor Washington, D.C. 20001 zack.fabish@sierraclub.org
William Bradley Carver, Sr. Hall Booth Smith, P.C. 191 Peachtree Street, NE Suite 2900 Atlanta, GA 30303 bcarver@hallboothsmith.com	Simon Mahan Southern Renewable Energy Association 11610 Pleasant Ridge Road Suite 103 #176 Little Rock, AR 72223 simon@southernwind.org

This 7th day of December 2023.

Allison W. Pryor

Allison W. Pryor
Attorney for Georgia Power Company

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January 10, 2024

Ms. Sallie Tanner
Executive Secretary
Georgia Public Service Commission
244 Washington Street, SW
Atlanta, GA 30334-5701

Re: Georgia Power Company's 2023 Integrated Resource Plan Update; Docket No. 55378;

Dear Ms. Tanner:

Georgia Power Company ("Georgia Power" or the "Company") files this errata to its 2023 IRP Update Filing in Docket No. 55378. The Company identified the following errors to be corrected:

- **2023 IRP Update Main Document – DSM Exhibit A**: The cost effectiveness results within the Residential Thermostat Demand Response ("TSTAT DR") Program Performance Metrics were understated. The chart summarizing the TSTAT DR Program's cost effectiveness results found on page 40 of the 2023 IRP Update Main Document should be replaced with the following:

	Net Benefits		Ratio	
	2024	2025	2024	2025
TRC	$543,126	$296,331	1.30	1.17
RIM	-$1,425,624	-$1,143,294	0.62	0.64
Program Administrator	-$1,425,624	-$1,143,294	0.62	0.64
Participants Test	$1,968,750	$1,439,625	N/A	N/A
Societal Test	$543,126	$296,331	1.30	1.17

*Participants Test set to "N/A" since there are no incremental customer costs for the program.

  Notably, this change only impacts the program's cost-effectiveness results and has no impact on the program's implementation levels or estimated annual program costs. The Company will revise and file a supplemental data request response to the extent any are impacted, as appropriate.

- **Direct Testimony of Jeffrey R. Grubb, Francisco Valle, Lee Evans, and Michael A. Bush**: The Direct Testimony includes the following corrections:
  - On page 30, line 16, the word "liability" should instead be "reliability."

- On page 46, line 25, the words "optional DCL-1 tariff" should be "optional CL-1 tariff." The discussion within this question and answer is about the curtailable load program and not the DCL-1 tariff, which applies to the DER Colocation program.

If you have any questions, please call me at 404-885-3779.

Sincerely,

Allison W. Pryor

Allison W. Pryor

GPC EXHIBIT 9

Georgia Power

Bin 10230
241 Ralph McGill Boulevard, NE
Atlanta, GA 30308-3374

January 12, 2024

Ms. Sallie Tanner
Executive Secretary
Georgia Public Service Commission
244 Washington Street, SW
Atlanta, GA 30334-5701

RE: Georgia Power Company's 2023 Integrated Resource Plan Update;
Docket No. 55378

Dear Ms. Tanner:

In accordance with O.C.G.A. § 46-3A-1, et seq., and Georgia Public Service Commission (the "Commission") Rules 515-3-4-.06 through 515-3-4-.10, as applicable, Georgia Power Company ("Georgia Power") filed its 2023 Integrated Resource Plan ("IRP") Update on October 27, 2023. Included in the 2023 IRP Update is an Economic Analysis of Capacity Resources ("Economic Analysis") supporting the Company's request in this case. Georgia Power completed negotiations for the engineering, procurement, and construction ("EPC") for the three simple cycle combustion turbines at Plant Yates and entered into an EPC Agreement with a consortium of Mitsubishi Power Americas, Inc. and Black & Veatch Construction, Inc., effective as of January 12, 2024 ("Yates EPC Agreement"). As such, Georgia Power now files an Updated Economic Analysis to reflect the final terms and conditions of the contract and to remove the references to the Potential Acquisition of an Additional Ownership Interest in an Existing Generation Asset, which is no longer moving forward. Additional workpapers supporting the Updated Economic Analysis will be provided to Staff next week.

This filing is covered under the trade secret rules of the Commission as explained in the enclosed document regarding the basis for the assertion. Therefore, in addition to the trade secret document and per the Commission Staff's instructions, 16 copies and an electronic version of the redacted Updated Economic Analysis is enclosed for public disclosure.

Following the execution of the Yates EPC Agreement and in conjunction with filing the Updated Economic Analysis, Georgia Power separately filed supplemental responses to the following data requests:

- STF-JKA-2-2
- STF-JKA-2-19
- STF-JKA-2-22
- STF-DEA-3-6

Please contact Cheryl Johnson at 404-506-6837 if you have any questions regarding this filing.

Sincerely,

/s/ Kelley M. Balkcom
Kelley M. Balkcom
Director, Regulatory Affairs

Encl.

BEFORE THE GEORGIA PUBLIC SERVICE COMMISSION

GEORGIA POWER COMPANY
DOCKET NO. 55378

AFFIDAVIT AND BASIS FOR THE ASSERTION THAT PORTIONS OF THE INFORMATION SUBMITTED ARE PROTECTED TRADE SECRETS

As part of its 2023 Integrated Resource Plan Update ("2023 IRP Update"), filed in Docket No. 55378, Georgia Power Company ("Georgia Power" or the "Company") submits to the Georgia Public Service Commission an Updated Economic Analysis for Capacity Resources, which contains data supporting proposed projects in the 2023 IRP Update including Company-owned proposals, which include sensitive pricing, resource operational capability data, and development timelines, and also certain information regarding the Company's proprietary planning processes, financial data, technology screening assumptions, generic technology and resource cost information, specific resource, technology and avoided cost information, economic analyses, load and energy forecast data assumptions, and other data, including confidential details regarding current and future transmission projects (the "Information"). Certain portions of the Information are trade secrets of Georgia Power and Southern Company and their affiliates and is therefore protected from public disclosure under Commission Rule 515-3-1-.11.

The trade secret portions of the Information derive economic value from not being generally known to, and not being readily ascertainable by proper means by other persons who can obtain economic value from their disclosure or use. Specifically, the trade secret portions of the Information contained herein include competitively sensitive pricing and operational capability data, including project development timelines where applicable, specific to the resources under contract within each power purchase agreement or proposed to be developed. If the Information were made public, competitors, bidders, and suppliers could use the Information to unfairly manipulate the request for proposals process and competitive market to structure future bids and set an artificial price floor to arbitrarily increase prices to the detriment of the Company and its customers. Public dissemination of the Information would undermine Georgia Power's ability to negotiate the best price and contract terms and could harm the Company's ability to secure the best cost bids and resources for the benefit of customers. In addition, the terms of the power purchase agreements themselves provides for the confidentiality and protection of the Information. Compromising the confidentiality of such Information could harm Georgia Power in future PPA negotiations, as counterparties may fear compelled disclosure of key contractual terms. Lastly, the Company's competitors are not required to reveal or publish similar information.

The trade secret portions of the Information also contain competitively sensitive cost information related to available technology options, processes and data used by Georgia Power in analyzing resource addition schedules, financial data used in the Company's resource analyses, and other confidential details including data supporting resource economic evaluations. Public dissemination of the trade secret portions of the Information would allow Georgia Power's competitors and suppliers to have access to such processes and strategies and thereby gain an unfair competitive advantage in the marketplace. Competitors would obtain an unfair advantage because they are not required to reveal similar information and can utilize such trade secret portions of the Information to manipulate pricing and timing of supply to the disadvantage of Georgia Power. Competitors would also unfairly benefit in having access and insight into the Company's planning processes and methodologies. This competitive advantage for the Company's suppliers and competitors would mean that Georgia Power will potentially pay higher prices to suppliers, ultimately harming Georgia Power and its customers.

Certain trade secret portions of the Information provided include load and energy forecast data assumptions such as projections of new customer load the Company assesses it may be selected to serve in the near future, estimates of parameter inputs for modeling probability distributions, and the values of any external adjustments made to the forecast. Public disclosure of the Information could unfairly alter the Company's negotiation position with prospective new customers, which could result in a less advantageous rate being secured and thus potentially harming retail customers through higher rates. In addition, the Company's competitors are not required to file their respective competitive intelligence information.

Additionally, the Information contains competitively sensitive cost information related to the prices Georgia Power has estimated for transmission equipment and specific details related to the Company's transmission infrastructure. Public dissemination of the Information would allow Georgia Power's competitors and suppliers to have access to the costs paid by the Company and insight into the Company's transmission planning process. Access to the Information would also allow competitors to gain specific insight into the Company's technical analysis regarding planned projects. Competitors would obtain an unfair advantage because they are not required to reveal similar information and can structure the pricing for competing products based on the Information. In the event the Information was released, it is quite likely that suppliers would use the Information to set the floor in establishing their own prices, thus artificially and inefficiently setting a market price that may not be representative of the best cost that the market could offer. Competitors would also unfairly benefit in having access and insight into the Company's planning processes and methodologies. This competitive advantage for the Company's suppliers and competitors would mean that Georgia Power will potentially pay higher prices to suppliers, ultimately harming Georgia Power.

The trade secret portions of the Information are subject to substantial procedures to maintain their secrecy. Only select Georgia Power and Southern Company personnel are granted access to the trade secret portions of the Information. Those personnel receive access only on a "need to know" basis. Parties outside Georgia Power and Southern Company affiliates and their legal counsel who have been granted access to the trade secret portions of the Information, if any, have been required to sign confidentiality agreements.

BEFORE THE GEORGIA PUBLIC SERVICE COMMISSION

In the Matter of	)	
	)	**Docket No. 55378**
Georgia Power Company's	)	
2023 Integrated Resource Plan Update	)	
	)	

VERIFICATION

Jeffrey R. Grubb, first being duly sworn, deposes and states that he has reviewed Georgia Power Company's revised economic analyses in the above-styled Docket and that such information was prepared at his direction and under his supervision and that the information included in such responses is accurate to the best of his knowledge and that the specific information designated as trade secret constitute trade secrets pursuant to Article 27 of Chapter 1 of Title 10 of the Official Code of Georgia.

Jeffrey R. Grubb
Director of Resource Policy and Planning
Georgia Power Company

Subscribed and sworn to before me this 10th day of January 2024.

Notary Public

My Commission expires:

4/26/26

DANA L MCLEAN NOTARY PUBLIC COWETA COUNTY GEORGIA EXPIRES APRIL 26, 2026



Updated Economic Analysis of Capacity Resources

2023 Integrated Resource Plan Update

1. Introduction

As stated in the 2023 Integrated Resource Plan ("IRP") Update, Georgia's economy has continued to thrive, bringing rapid economic expansion and an unprecedented increase in the demand for energy to the state. This rapid economic expansion requires Georgia Power Company ("Georgia Power" or "GPC") to develop or procure additional capacity resources so that it can continue to provide reliable electric service to its customers. Therefore, Southern Company Services ("SCS") and Georgia Power (collectively, the "Company") evaluated numerous resources that can provide the capacity necessary to meet its customers' energy needs during this period of extraordinary economic growth in Georgia. This document discusses the Company's economic evaluation of these resources in support of the 2023 IRP Update.

2. Approach

The Company's economic evaluation compares the costs and benefits of resource options identified in the 2023 IRP Update. The evaluation ranks the resources to determine the least cost options that are able to meet the Company's capacity need. To capture the uncertainty of future fuel prices and carbon pressure, the analysis was performed over a range of fuel prices and carbon price paths, resulting in five distinct planning scenarios. This approach is consistent with typical economic evaluations of resources proposed to meet forecasted needs, such as a capacity request for proposals ("RFP") and similar procurements. These factors were incorporated within the Company's economic evaluation of resources, as described in this document.

3. Assumptions

The Company modeled the incremental costs and benefits of each resource it evaluated. Costs include capacity costs, capital costs, fixed operations and maintenance ("O&M") costs, start-up costs, natural gas transportation charges, and other incremental cost to customers. Utilizing the Aurora model, the Company quantified the production cost savings (i.e., energy benefits) of each resource, while also capturing the projected commodity fuel and variable O&M costs.

3.1. Power Purchase Agreements ("PPA")

For each PPA, the Company's economic evaluation includes the cost of the PPA as set forth by the terms of each PPA. Capacity costs are fixed costs associated with the capacity payment for each PPA. The start-up cost for a PPA represents the projected cost to start a thermal generating unit, taking into account the anticipated number of starts required under economic dispatch and the cost characteristics of the individual resources. For contracted resources, the per-start cost was specified in the PPA. Firm transportation ("FT") cost was included for resources that require additional FT, or firm access to natural gas pipeline infrastructure, to provide reliable service. An additional sum of $3/kW-yr was included consistent with the additional sum approved for capacity resources in the 2022 IRP[1] and requested in this 2023 IRP Update. The analysis also considered an accounting lease cost for applicable PPA proposals. Variable O&M, fuel costs, and emissions costs are netted out of the energy benefits and are derived by the production cost model, Aurora. For any sales to a third party, the expected sales revenues are credited as a benefit to customers.

3.2. New Company-owned Resources

The costs of new construction for proposed Company-owned resources were included in the economic evaluation. In-service capital costs represent the cost of construction, financing costs, and property taxes. Maintenance capital costs are the projected capital expenditures necessary to maintain reliable operation through the assumed useful life of a resource. O&M includes labor, materials, support services, and overhead costs necessary to operate the plant. O&M costs are broken out between fixed and variable O&M for each study. Fixed O&M is directly reflected in the economic valuation. Variable O&M, fuel costs, and emissions costs are netted out of the energy benefits and are derived by the production cost model, Aurora.

The Inflation Reduction Act ("IRA") provides opportunities for Investment Tax Credits ("ITC") and Production Tax Credits ("PTC") that directly benefit customers. The Company included the assumed benefits of the ITC for battery energy storage systems ("BESS") and PTC for solar resources. The impact of the ITC on BESS is reflected in the in-service capital costs. The PTC benefits for solar resources are reflected in the additional benefits.

[1] Docket No. 44160.

3.3. Acquisitions

The Company did not include the potential option to acquire an additional ownership interest in an existing generating asset within the Southern Company footprint because the parties were unable to reach agreement, as described in the Company's Direct Testimony filed on December 4, 2023.

3.4. Transmission

The Company also completed transmission screening analyses to determine the impacts of each resource. These screening analyses include considerations related to deliverability for each resource, which is the ability to transfer energy from the resource across the bulk power system. The screening analyses identified certain reliability issues that can necessitate transmission system upgrades, which can take several years to complete. Therefore, the Company included both the capital costs as well as the potential impact to capacity contributions in the economic assessment of each resource. The impacts to the capacity contributions, or timing of transmission system upgrades, are reflected in the term equalization costs line items of the Company's economic evaluation. Transmission system upgrade costs are included in the transmission line item of the evaluation.

3.5. Term Equalization

To conduct an evaluation of proposed resources with varying unit lives and term lengths, the evaluation period must be based upon the life of the longest-lived resource being evaluated. For the 2023 IRP Update that resource is Plant Yates Units 8-10, which has an expected service life of 45 years. The Company analyzed the economics of each resource consistent with its proposed term, or the expected remaining service life in the case of resources the Company proposes acquiring. The Company then performed a similar economic assessment for replacement capacity for the balance of the evaluation period. The replacement capacity used for the balance of the period was assumed to be a dual-fueled combustion turbine ("CT"), consistent with the cost of Plant Yates Units 8-10. Using this method, the Company was able to evaluate each resource on a comparable basis over a 45-year period.

4. Summary of Study Results

The following tables represent the net present value ("NPV") of the net costs associated with each resource that was evaluated. The results are calculated by comparing the cost of each resource net of its benefits, which include energy benefits and market or acquisition-related revenues. The NPV is then divided by the capacity contribution of each resource to the Company's target reserve margins. This provides a $/kW result for comparison purposes. The results across each scenario are averaged and ranked to establish a relative ranking of each resource.

4.1. Ranking and Summary of Results (2024 NPV $/kW)

		NPV $/kW					
Rank	Project	LG0	MG0	HG0	MG20	MG50	Average
1	Robins BESS	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**
2	Moody BESS	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**
3	MPC PPA	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**
4	Santa Rosa PPA	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**
5	Yates 8-10 CTs	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**
6	200 MW BESS + Solar	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**

4.2. Results for MG0 (2024 NPV $/kW)

2024 NPV ($/kW)	Robins BESS	Moody BESS	MPC PPA	Santa Rosa PPA	Yates 8-10 CTs	200 MW BESS + Solar
Winter Capacity Equivalence	115	45	750	230	1,070	200
PPA Term or Life (years)	20	20	5	5	46	20
Capacity Costs	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
Accounting Lease	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
Additional Sum	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
InService Capital	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
Environmental	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
Maintenance Capital	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
Fixed O&M	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
FT	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
Revenue Requirement	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
Transmission	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
Term Equalization	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
System Costs	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
Energy Benefit	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
Additional Benefits	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
Total Benefits	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
Net Costs	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED

4.3. Results for MG20

2024 NPV ($/kW)	Robins BESS	Moody BESS	MPC PPA	Santa Rosa PPA	Yates 8-10 CTs	200 MW BESS + Solar
Winter Capacity Equivalence	115	45	750	230	1,070	200
PPA Term or Life (years)	20	20	5	5	46	20
Capacity Costs	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
Accounting Lease	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
Additional Sum	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
InService Capital	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
Environmental	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
Maintenance Capital	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
Fixed O&M	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
FT	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
Revenue Requirement	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
Transmission	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
Term Equalization	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
System Costs	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
Energy Benefit	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
Additional Benefits	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
Total Benefits	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
Net Costs	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED

4.4. Results for MG50

2024 NPV ($/kW)	Robins BESS	Moody BESS	MPC PPA	Santa Rosa PPA	Yates 8-10 CTs	200 MW BESS + Solar
Winter Capacity Equivalence	115	45	750	230	1,070	200
PPA Term or Life (years)	20	20	5	5	46	20
Capacity Costs	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
Accounting Lease	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
Additional Sum	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
InService Capital	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
Environmental	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
Maintenance Capital	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
Fixed O&M	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
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Revenue Requirement	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
Transmission	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
Term Equalization	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
System Costs	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
Energy Benefit	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
Additional Benefits	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
Total Benefits	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
Net Costs	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED

4.5. Results for LG0

2024 NPV ($/kW)	Robins BESS	Moody BESS	MPC PPA	Santa Rosa PPA	Yates 8-10 CTs	200 MW BESS + Solar
Winter Capacity Equivalence	115	45	750	230	1,070	200
PPA Term or Life (years)	20	20	5	5	46	20
Capacity Costs	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
Accounting Lease	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
Additional Sum	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
InService Capital	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
Environmental	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
Maintenance Capital	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
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Revenue Requirement	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
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System Costs	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
Energy Benefit	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
Additional Benefits	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
Total Benefits	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
Net Costs	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED

4.6. Results for HG0

2024 NPV ($/kW)	Robins BESS	Moody BESS	MPC PPA	Santa Rosa PPA	Yates 8-10 CTs	200 MW BESS + Solar
Winter Capacity Equivalence	115	45	750	230	1,070	200
PPA Term or Life (years)	20	20	5	5	46	20
Capacity Costs	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
Accounting Lease	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
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InService Capital	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
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Fixed O&M	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
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Revenue Requirement	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
Transmission	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
Term Equalization	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
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Energy Benefit	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
Additional Benefits	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
Total Benefits	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
Net Costs	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED

Due to the voluminous trade secret information and substantial use of formulas required to preserve functionality, this file is redacted in its entirety.

CERTIFICATE OF SERVICE

I hereby certify that I have this day served a copy of the within and foregoing GEORGIA POWER COMPANY'S UPDATED ECONOMIC ANALYSIS OF CAPACITY RESOURCES IN DOCKET NO. 55378 upon all parties listed below via electronic service or by hand delivery and addressed as follows:

Sallie Tanner Executive Secretary Georgia Public Service Commission 244 Washington Street, SW Atlanta, GA 30334 stanner@psc.ga.gov	Preston Thomas Ginny Davis Georgia Public Service Commission 244 Washington Street, SW Atlanta, GA 30334 pthomas@psc.ga.gov gdavis@psc.ga.gov
Charles B. Jones, III Lloyd Avram Georgia Association of Manufacturers The Hurt Building 50 Hurt Plaza, Suite 1620 Atlanta, Georgia 30303 (404) 688-0555 cjones@gamfg.org lavram@gamfg.org	Jeffry C. Pollock J. Pollock Incorporated 14323 South Outer 40 Road, Suite 206N Town and Country, Missouri 63017-5734 (314) 878-5814 (314) 878-7339 (fax) jcp@jpollockinc.com
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This 12th day of January 2024.

Allison W. Pryor

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Georgia Power

DOCKET NO. 55378

2023 REQUEST FOR INFORMATION FOR CAPACITY RESOURCES – SUMMARY OF RESULTS

Georgia Power Company

4 December 2023

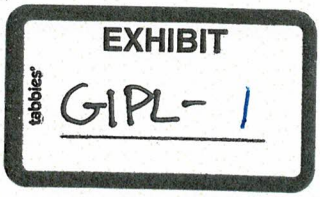


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1.0 Overview of the RFI

1.1 Purpose and Scope

On September 26, 2023, Georgia Power Company ("Georgia Power" or the "Company") issued a Request for Information ("RFI") to gather market information regarding the availability of existing and planned Capacity Resources for the capacity need identified for years 2026 through 2028, the timeframe being addressed in the Company's 2023 IRP Update, as well as for years 2029 through 2031, the time period to be addressed in the Company's 2029-2031 All-Source Request for Proposals ("RFP"). The primary objective of the RFI was to provide Georgia Power with current market information on the size, cost, technology, availability, risk, and operational and technical attributes of any reliable resource that can meet the firmness and dispatchability requirements, as defined in the RFI, including, but not limited to: (i) Standalone Energy Storage System ("ESS") with grid charging capability; (ii) ESS with a Renewable Resource[1] with grid charging capability; or (iii) thermal generation (e.g. natural gas, oil fired) (each a "Capacity Resource" and collectively, "Resource Types").

Georgia Power sought information regarding projects that could commence delivery on or after November 1, 2026, but no later than November 1, 2030 pursuant to either a Power Purchase Agreement ("PPA"), Asset Purchase Agreement ("APA"), or a Build Transfer Agreements ("BTA"). Each Capacity Resource identified in the RFI had to be at least one hundred megawatts (100 MW) in size, and a single resource could not exceed twelve hundred megawatts (1,200 MW). Georgia Power's interest included the availability of PPAs with a term of five (5), ten (10), fifteen (15), or twenty (20) years and the ability to deliver energy in the Southern Company Transmission System[2] and Georgia Integrated Transmission System[3] (collectively, "Southern Transmission Territory" or "STT") or at an interface between the STT and another transmission service provider. Capacity Resources with ESS with grid charging capability, including those paired with a Renewable Resource, were required to be interconnected to the Southern Company Transmission System to assure Georgia Power can provide (toll) the energy, and solely charge energy from the Southern Company Transmission System. Regarding Standalone ESS Capacity Resources, Georgia Power would provide (toll) all the energy required to charge a Standalone ESS, excluding station service. Georgia Power considered APAs for existing facilities and BTAs for new projects located within the STT offering 100% ownership of the existing or new Capacity Resource. Georgia Power did not consider responses for partial unit(s) of an existing Capacity Resource or a non-ownership interest in an existing Capacity Resource, unless Georgia Power already had an interest in the existing Capacity Resource or already owned units on the facility site.

---

[1] Renewable Resource: A renewable generating facility that: (i) has or will have a point of interconnection on the Southern Company Transmission System; (ii) must be at least 100 MW in size; and (iii) utilizes a sustainable, perpetual, or renewable fuel.

[2] Southern Company Transmission System: The integrated high voltage electricity transmission systems of the electric utility operating companies of the Southern Companies (Georgia Power Company, Alabama Power Company, and Mississippi Power Company).

[3] Georgia Integrated Transmission System ("Georgia ITS"): An integrated transmission system owned individually by Georgia Power Company, Georgia Transmission Corporation, Municipal Electric Authority of Georgia ("MEAG") Power, and Dalton Utilities and operated to transmit, receive, or distribute electric energy or capacity.

1.2 RFI Process

Georgia Power's RFI was intended solely to solicit information to assist with future resource planning efforts and to gain knowledge of available capacity and generation resources. To solicit the market for the RFI, Georgia Power utilized various internal and external communication channels to notify the market and provide an opportunity to respond to the RFI. The communication channels included: GeorgiaPower.com; industry email distribution to over five hundred (500) Georgia Power contacts from previous RFPs and PPA or business counterparties; social media ad on LinkedIn; Georgia Power News Center article; and targeted media outreach to a group of energy industry publications. GeorgiaPower.com was the main landing page for interested parties to access information about the RFI and to access a link to register for the OnBase website ("RFI Website"). The RFI Website, developed and managed by Georgia Power, was the host platform for interested parties to submit responses. In addition, the RFI Website provided notifications to registered users and a forum for questions and answers regarding the RFI. Georgia Power invited all interested parties to submit a response to the RFI between September 26 and October 24, 2023.

1.3 Market Outreach

As mentioned in Section 1.2 (RFI Process), Georgia Power broadly publicized the RFI by notifying various industry contacts, past RFP participants, entities that expressed interest in past RFPs, and current PPA counterparties. The notification was sent as an "email blast" (see Attachment B). In addition, the Company promoted the RFI on social media through LinkedIn. The social media ad targeted a range of industries and job titles with an overall ad impression, or number of times the ad/post was visible, of 71,718. Please see Tables 1-3-1 and 1-3-2 below for performance metrics of the social media ad on LinkedIn.

Table 1-3-1

Ad Performance	
Clicks[4]	707
Impressions[5]	71,718
Average Click through Rate (CTR)[6]	0.99%
Total Social Actions[7]	1,420
Total Engagement [8]	2,211

Table 1-3-2

Top Industries Reached
Electric Industries
Utilities
Natural Gas Distribution
Top Job Titles Reached
Project Manager
Engineer
Operational Specialist

Overall, throughout the RFI timeframe, there were a total of 1,400 page views of the Georgia Power RFI Website and 921 unique visitors who visited the RFI Website at least once.

[4] Number of clicks the Ad received.
[5] The number of times each post was visible.
[6] The number of clicks divided by impression.
[7] Volume of social engagement ad received. Includes reactions, comments, shares, follow clicks, reaction clicks, and other engagements.
[8] The sum of all social actions, clicks to Landing page, and clicks to LinkedIn Page, both chargeable and free.

2.0 RFI Results

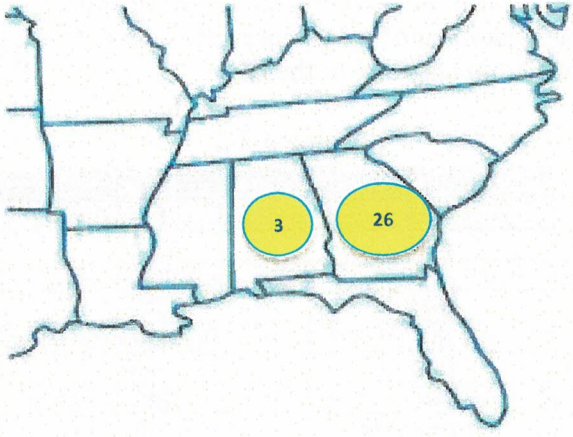
2.1 Summary of Responses

Georgia Power received forty-four (44) unique submissions[9] to the RFI. Of the responses received, thirty-seven (37) were mutually exclusive[10] potential projects. Of these thirty-seven (37) potential projects, five (5) submissions included solar only resources, which did not meet the Capacity Resource requirements of the RFI (see Attachment A), which left thirty-two (32) total qualifying submissions. Of the thirty-two (32) qualifying submissions, only two (2) projects were existing Capacity Resources. These two existing resources are not available as additional resources to the Company in the timeframe addressed in the Company's 2023 IRP Update. The remaining qualifying submissions either indicated new or planned potential projects. RFI participants represented twenty-two (22) different companies with several companies providing multiple responses for different project types and interest in differing contract types.

2.2 Location

Of the qualifying submissions, three (3) submissions indicated potential new or planned projects located in Alabama, with all remaining submissions that listed a project state indicating potential projects within the state of Georgia. Three submissions did not identify a state for the proposed project. See the map in Figure 2-2-1 below.

Figure 2-2-1



2.3 Capacity and Resource Type and Availability

Georgia Power received a robust response to the RFI, with the potential total capacity equaling 6,667 MW. See Table 2-3-1 below for a breakdown of Resource Types and capacity. The RFI results indicated the availability of two (2) existing projects, both thermal Resource Types, while all other qualifying submissions indicated either new or planned projects in various stages of development. RFI participants were primarily interested in a PPA option for ESS with a Renewable Resource, with grid charging capability. More specifically, RFI participants offered projects with battery energy storage

[9] Unique submissions include multiple submissions for the same project offering different contract types (e.g., PPA, APA, BTA).
[10] Mutually exclusive submissions indicate the number of individual projects.

systems paired with solar. Georgia Power received several responses that included an interest to provide Georgia Power resources pursuant to BTAs. Georgia Power did not receive any indication from the RFI participants of any plans to develop new natural gas Capacity Resources.

Table 0-3-1

Breakdown of Resource Types[11]		
Capacity Resource Type	# of Responses	Sum of Capacity (MW)
ESS Standalone[12]	13	2,695
ESS + solar[13]	12	1,680
ESS Other[14]	4	769
Thermal (CC / CT)	2	1,243
Nuclear Energy	1	280
Total	**32**	**6,667**

As a result of the RFI, Georgia Power collected valuable market information regarding existing or planned Capacity Resources that could commence delivery between the 2026 – 2030 timeframes. As shown in Table 2-3-2, a total of 3,777 MW in Capacity Resources indicated they are available to be constructed within the 2026-2028 timeframe and a total of 2,146 MW indicated they are available within the 2029-2031timeframe. For the 2025-2027 timeframe, those resources are not available to meet the Company's needs as being addressed in the 2023 IRP Update. There is not enough time for an RFP to be conducted, resources to be constructed following certification, and transmission projects to be identified and completed to allow delivery by the end of calendar years 2025, 2026 or 2027. Table 2-3-2 provides a breakdown of the Capacity Resources' indicated availability based on calendar years identified in response to the RFI.

Table 0-3-2

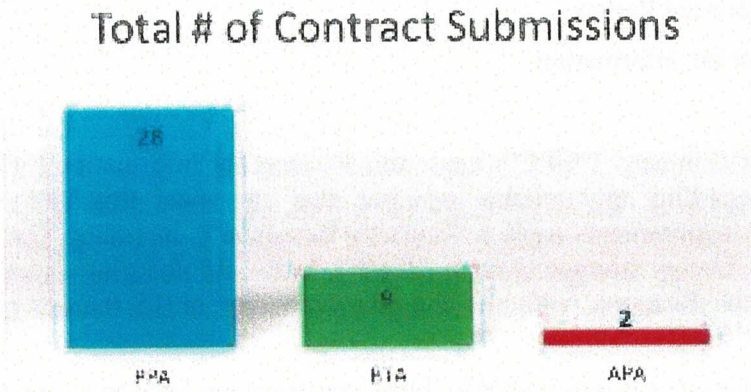
Availability Year	Total
2025	100
2026	1,110
2027	1,495
2028	1,072
2029	420
2030	1,446
2031	280
Not Provided	744
Totals (MW)	**6,667**

[11] As described in Section 2.1, 5 of the submissions included solar only resources, which did not meet the Capacity Resource qualifications of the RFI (See Attachment A).
[12] ESS Standalone generally represents battery energy storage systems as the "ESS" device.
[13] ESS + solar generally represents battery energy storage systems as the "ESS" device.
[14] ESS "Other" includes responses that indicate non-standard storage technologies (e.g., Hydrogen Fuel Cells, Pumped Heat, Compressed Air, and Superconducting Magnetics.

2.4 Contract Type

In response to Georgia Power's request for feedback on offering resources pursuant to the PPA, APA, and BTA contract types, the market responded with interest in all three contract types. Of the thirty-two (32) qualifying submissions, Figure 2-4-1 below shows a breakdown of submissions by contract type.[15] Of note, RFI participants were primarily interested in a PPA option for ESS Standalone or ESS paired with a Renewable Resource, with grid charging capability.

Figure 2-4-1



2.5 Conclusion

The Georgia Power RFI provided the Company with valuable market information to assist with current and future resource planning efforts and facilitate Georgia Power's preparation for the 2029-2031 All-Source RFP. As noted above, no existing resources were identified which could help meet the capacity needs being addressed in the Company's 2023 IRP Update. Of the 6,667 MW of Capacity Resources potentially available in the market, only 1,243 MW of existing capacity was identified and appears to be available during the 2029-2031 timeframe. RFI participants indicated the most interest in providing planned or new ESS Standalone and ESS with a Renewable Resource, with grid charge capability, with significant interest in providing planned or new projects through either a PPA or BTA.

15 Five (5) projects indicated alternate Contract Types.

Attachment A RFI Document

Resource Policy & Planning
241 Ralph McGill Blvd
Bin #10194
Atlanta, GA 30308

September 26, 2023

To: All Interested Parties

Re: Request for Information

Georgia Power Company ("GPC") issues this Request for Information ("RFI") to request information regarding any reliable resource that can meet this RFI's firmness and dispatchability requirements (each a "Capacity Resource"), including, but not limited to: (i) Standalone Energy Storage System ("ESS"), with grid charging capability; (ii) ESS, with a Renewable Resource, with grid charging capability; or (iii) thermal generation (e.g., natural gas, oil fired).

Firmness includes, but is not limited to, Firm Transmission Service as defined in this RFI. Dispatchability includes, but is not limited to, the ability to operate the facility on Automatic Generation Control ("**AGC**") as defined in this RFI or electronically scheduled to adjust the regulation of the facility to deliver energy from the Capacity Resource.

Each Capacity Resource identified must be at least one hundred megawatts (100 MW) in size, and a single resource may not exceed twelve hundred megawatts (1,200 MW). GPC invites all interested parties to submit a response to this RFI.

GPC will manage the OnBase website ("**RFI Website**") as the host platform for this RFI. All responses to this RFI must be submitted through the RFI Website. In addition, the RFI Website will provide notifications to registered users and a forum for questions and answers regarding this RFI.

The RFI Website is located on GPC's website at www.GeorgiaPower.com/rfi.

GPC will accept RFI responses through the RFI Website from **September 26, 2023,** through **October 24, 2023**.

REQUEST FOR INFORMATION

All-Source RFI for Capacity

Background

GPC's 2022 Integrated Resource Plan, as approved by the Georgia Public Service Commission ("**Commission**") in Docket No. 44160 ("**2022 IRP**"), identified a need for additional Capacity Resources. On July 21, 2022, the Commission issued its 2022 IRP Final Order, which amended and approved the Stipulation requiring GPC to conduct an all-

source solicitation to address capacity needs identified by GPC. In the 2022 IRP, GPC estimated approximately 3,723 MW of Capacity Resources would be necessary to satisfy GPC's capacity needs through Winter 2031, but current projections indicate greater capacity needs and needs earlier than the 2029-2031 timeframe. In light of these projections, GPC issues this RFI to collect information on existing or planned Capacity Resources that can meet the firmness and dispatchability requirements set forth in this RFI and commence delivery to GPC between the 2026 – 2030 timeframe.

1.0 Description

GPC seeks identification and associated details regarding any Capacity Resource that can meet the requirements of this RFI that include the following technologies:

(i) Standalone ESS with grid charge capability;
(ii) ESS with a Renewable Resource, with grid charge capability; or
(iii) Thermal generation (e.g., natural gas, oil fired).

Capacity Resources must: (i) provide firm capacity and energy from one or more dedicated generation units; (ii) be fully dispatchable to meet GPC's scheduling instructions; and (iii) be capable of operating on AGC. Firmness includes, but is not limited to, Firm Transmission Service.

The primary objective of this RFI is to provide GPC with market information on the size, cost, technology, availability, and deliverability of Capacity Resources. GPC may consider response information based on economics, risk, and operational and technical attributes using GPC's most recent resource planning assumptions.

Information submitted in response to this RFI will become the property of GPC and will be made available to the Commission and Commission Staff (**"Staff"**). GPC and respondents acknowledge that portions of these responses may contain confidential information. Please note that GPC will protect the confidential nature of responses and will not share publicly information that is designated in writing as confidential. However, respondents understand and acknowledge that confidential information may need to be disclosed by GPC in connection with its regulatory obligations before the Commission. Should this occur, GPC will request confidential treatment of confidential information in accordance with the Commission's rules regarding trade secrets, but GPC makes no assurance or commitment regarding GPC's ability to obtain confidential treatment from the Commission.

THIS IS A REQUEST FOR INFORMATION ONLY. GPC issues this RFI solely to solicit information to assist with future resource planning efforts and to gain knowledge of available capacity and generation resources, along with an estimate of their corresponding costs. This RFI is not a request for proposals (**"RFP"**) and is intended solely to inform GPC about available and planned Capacity Resources. After review of the RFI responses, GPC may or may not explore the potential for future procurement options in connection with one or more Capacity Resources at its sole discretion. This RFI must not be construed as an intent, commitment, or promise to contract nor to acquire assets, resources, or products offered. All costs associated with responding to this RFI will be solely at the responding party's expense. Abstaining from responding to this RFI will not preclude participation in any All-Source RFP issued by GPC in the future.

2.0 Scope

GPC requests information regarding existing or planned Capacity Resources that could be procured by GPC through a:

(i) Power Purchase Agreement ("**PPA**");

(ii) Asset Purchase Agreement ("**APA**"); or

(iii) Build Transfer Agreement ("**BTA**")

to commence delivery to GPC during the 2026 – 2030 timeframe. Responses must indicate a commencement of service to GPC on or after November 1, 2026, but no later than November 1, 2030.

Capacity Resources available to commence delivery as early as November 1, 2024, should indicate such availability prior to the requested 2026 – 2030 timeframe.

3.0 Response Instructions

GPC requests the information described below about existing or potential Capacity Resources that might be available to serve GPC customers in Georgia in the requested timeframe. This list is illustrative and not all topics are required to respond to this RFI. Information referenced as *optional* is not required. This RFI uses the following definitions:

- **Automatic Generation Control ("AGC")**: The equipment and capability of a Capacity Resource to automatically adjust the energy quantity output within the applicable balancing authority for the purpose of interchange balancing, and specifically, the Capacity Resource capability of accepting a set point electronically and the automatic adjustment and regulation of the facility's energy production output to meet that set point.
- **Firm Transmission Service**: Transmission service that has: (i) been procured and is held by a seller under the applicable open access transmission tariff on each applicable Electric System for the delivery of energy from the facility to the point of delivery; and (ii) a priority equal to the highest level of firm transmission service available to any person on that Electric System from: (a) COD and through the PPA term; or (b) APA or BTA closing and through the remainder of the facility design life, as applicable.
- **Electric System**: The network of electric generation, transmission, or distribution facilities owned or operated by GPC or other electric utilities.
- **Georgia ITS**: The Georgia Integrated Transmission System, which is owned individually by GPC, Georgia Transmission Corporation, Municipal Electric Authority of Georgia ("**MEAG**") Power, and Dalton Utilities and operated as an integrated transmission system for transmitting, receiving, or distributing electric energy or capacity.
- **Renewable Resource**: A renewable generating facility that: (i) has or will have a point of interconnection ("**POI**") on the Southern Company Transmission System; (ii) must be at least 100 MW in size; and (iii) utilizes a sustainable, perpetual, or renewable fuel.

- **Southern Balancing Authority Area ("SBAA")**: A North American Electric Reliability Corporation ("**NERC**") and Southeastern Electric Reliability Corporation ("**SERC**") recognized balancing authority area. For the avoidance of doubt, the SBAA includes the Southern Transmission Territory.
- **Southern Company Transmission System**: The integrated high voltage electricity transmission systems of the electric utility operating companies of the Southern Companies (GPC, Alabama Power Company, and Mississippi Power Company).
- **Southern Transmission Territory ("STT")**: The Southern Company Transmission System and the Georgia ITS.
- **Standalone ESS:** An ESS that is not paired with a Renewable Resource.

- **General Information Requested:**
  - Facility or Project name
  - Facility location (state, county, city, and transmission interconnection provider)
  - Facility status (Is the project new or existing? Is the project currently in operation or in construction?)
  - Commercial operation date ("**COD**") or projected COD
  - Contingencies associated with facility COD
  - Nameplate capacity of facility and each unit (each Capacity Resource identified must be at least 100 MW in size and no single resource may exceed 1,200 MW)
  - Delivery commencement date (date when existing or projected capacity would be available to GPC) and any contingencies or restrictions on commencement
  - Actual or projected winter and summer capacity (MW) of facility
  - Facility data (generation technology type, vendor, unit type and configuration), and remaining facility life at delivery commencement date (years)
  - Facility or unit efficiency measures: average heat rates at maximum and minimum operating capacities for thermal resources or roundtrip efficiency for ESS (*optional*)
  - Provide any additional summary data regarding facility operating parameters (*optional*)
  - Fuel supply plan (if applicable) (*optional*)

- **Product-Specific Information Requested:**
  - **Consideration of PPAs.** GPC will consider Capacity Resources: (i) for PPAs with a term of 5, 10, 15, or 20 years; and (ii) able to deliver energy in

the STT or at an interface between the STT and another transmission service provider, except that Capacity Resources with ESS must be interconnected to the Southern Company Transmission System.

Please provide indicative pricing for the following:

- Capacity pricing $/kW- month and escalation rate (%)
- First year variable O&M cost ($MWh) and escalation rate (%) (optional)
- First year O&M startup costs ($/start) and escalation rate (%) (optional)
- Fuel pricing (if applicable); GPC toll is preferred but if existing fuel plan, please provide (*optional*)

- **Consideration of APAs.** GPC will consider APA projects for an existing Capacity Resource located within the STT. An APA must offer 100% ownership of the existing Capacity Resource. GPC will not consider responses for partial unit(s) of an existing Capacity Resource or a non-ownership interest in an existing Capacity Resource, unless GPC already has an interest in the existing Capacity Resource or already owns units on the facility site.

  Please provide indicative pricing for the following:

  - Facility total project price $(2023)
  - First year variable O&M cost ($/MWh) and escalation rate (%) (*optional*)
  - First year fixed O&M cost ($/kW) and escalation rate (%) (*optional*)
  - Start-up costs: ($/start) (*optional*)
  - Fuel pricing (if applicable) (*optional*)
  - Projected annual maintenance (weeks per year on average) (*optional*)
  - Historical availability (%) (*optional*)
  - Expected future availability (%, average annual over the remaining useful life) (*optional*)

- **Consideration of BTAs.** GPC will consider BTA facilities for a new Capacity Resource located within the STT. A BTA must offer 100% ownership of the new Capacity Resource.

  Please provide indicative pricing for the following:

  - Facility total project price $(2023)
  - First year variable O&M cost ($/MWh) and escalation rate (%) (*optional*)
  - First year fixed O&M cost ($/kW) and escalation rate (%) (*optional*)
  - Start-up costs: ($/start) (*optional*)

- Fuel pricing (if applicable) (*optional*)
- Projected annual maintenance (weeks per year on average) (*optional*)
- Expected future availability (%, average annual over the useful life) (*optional*)

- **Energy Storage Specifications and Information Requested:**
  - Any ESS Capacity Resource must be able to comply with Southern Company's Transmission's Operating Policy for Inverter Based Electric Storage Resources interconnecting to the Southern Company Transmission System, as appropriate, which may be found at:

    https://www.oasis.oati.com/woa/docs/SOCO/SOCOdocs/Inverter-Based_Electric_Storage_Operating_Policy.pdf.
  - **Standalone ESS.** A response identifying a Standalone ESS Capacity Resource must provide: (i) a description of the ESS; (ii) if offering a PPA, the plan to maintain the ESS to ensure the ESS performs as considered for the PPA term; (iii) the total expected ESS capacity (AC); and (iv) an annual schedule of the expected roundtrip efficiency for the term (PPA responses) or remaining facility design life (APA/BTA responses), as applicable. GPC must have the exclusive right to: (a) discharge; and (b) charge, without penalty, by issuing scheduling instructions. To assure GPC can toll the energy, a Standalone ESS must be interconnected to, and solely charged from, the Southern Company Transmission System. GPC will provide (toll) all the energy required to charge a Standalone ESS, excluding station service.
  - **ESS with Renewable Resource.** In addition to the information required above for Standalone ESS, including grid charge capability, a response identifying an ESS with Renewable Resource must also include: (i) a description of the Renewable Resource (including the generation type of the Renewable Resource (e.g., solar panels, wind turbines)); (ii) the total expected capacity (AC) from the Renewable Resource; and (iii) a profile reflecting the Renewable Resource, to demonstrate the charging contribution of the Renewable Resource for the ESS.

- **Transmission Information Requested:**
  - Existing or likely point(s) of interconnection and interconnection status (explain any current plans or limiting factors).
  - Interconnection or interconnection status must be for a large generator interconnection agreement.
  - As applicable for new resources, please provide the facility interconnection queue number or cluster group number.

- If located outside the SBAA, identify the transmission interconnection provider for the facility (not applicable for any Capacity Resource that: (i) includes ESS; or (ii) is related to an APA or BTA).

- **Project Financing Information Requested (Optional):**
  - Describe any experience financing commercial energy projects. (*optional*)
  - Please provide a description of the existing financing or financing plan for the facility (if applicable). (*optional*)

- **Other Information Requested:**
  - Briefly explain your interest and past experience in supplying energy and capacity, building or operating generation units, or negotiating generation asset sales and purchases. (*optional*)
  - Please indicate if you have entered into any PPA, APA, or BTA with GPC in the past. (*optional*)
  - Any additional information respondent deems relevant, including any optional references.
  - Briefly indicate if respondent is participating in other solicitations that may impact the information provided as part of this RFI.

4.0 Schedule

Event	Date
RFI Issued (RFI Website)	September 26, 2023
Last Day for Submitting Questions (RFI Website)	October 23, 2023
Due Date for Responses (RFI Website)	October 24, 2023, by 12 pm ET

5.0 Communications

RFI Website: The RFI Website is located on GPC's website at www.GeorgiaPower.com/rfi.

Attachment B Email Distribution Communication

Georgia Power

Request for Information Now Open

Georgia Power has issued a Request for Information (RFI) seeking information about available capacity resources to assist with its future resource planning efforts. Our RFI is open for submission now through October 24, 2023.

Eligibility

These capacity resources must meet our firmness and dispatchability requirements in the RFI including the following technologies:

i. Standalone Energy Storage System ("ESS"), with grid charging capability.
ii. ESS, with a Renewable Resource, with grid charging capability
iii. Thermal generation (e.g., natural gas, oil fired).

Each capacity resource identified must be at least 100 megawatts in size, and a single resource may not exceed 1,200 megawatts.

How to participate?

All interested parties are invited to submit a response regarding capability to provide purchase power agreements (PPAs), asset purchase agreements (APAs), or build transfer agreements (BTAs) on our dedicated RFI website between September 26, 2023 and October 24, 2023. The submission portal will also serve as a communication hub where registered users will receive updates and ask questions.

Additional Resources

For more information, visit the Georgia Power 2023 RFI website.

Georgia Power

Capacity Expansion Plan - MG0 (GPC Only)

Incremental

Year	CT w/ SCR	CC	CC w/ CCS	MPC PPA	Solar	Wind	Battery 4-hr (T1)	Battery 4-hr (T2)	Battery 4-hr (T3)	Battery 4-hr (T4)	Medium Duration Storage	Nuclear	Total
2024													
2025													
2026													
2027				750			900						**1650**
2028	300				750		780						**1830**
2029	1200						780	420					**2400**
2030		900			750								**1650**
2031		2700			180								**2880**
2032		300			180								**480**
2033		210			570	150							**930**
2034		210			570	120							**900**
2035	300	1710			600	600							**3210**
2036	600	1800			990	600		1500				300	**5790**
2037					990	300		210					**1500**
2038					990	600		270				300	**2160**
2039		210			990	300						210	**1710**
2040					990	600			1110			300	**3000**
2041					1020				540				**1560**
2042					1020	300							**1320**
2043					1020	300				300		300	**1920**
	2400	**8040**		**750**	**11610**	**3870**	**2460**	**2400**	**1650**	**300**		**1410**	**34890**

EXHIBIT
tabbies
GPL- 2

Cumulative

Year	CT w/ SCR	CC	CC w/ CCS	MPC PPA	Solar	Wind	Battery 4-hr (T1)	Battery 4-hr (T2)	Battery 4-hr (T3)	Battery 4-hr (T4)	Medium Duration Storage	Nuclear	Total
2024													
2025													
2026													
2027				750			900						**1650**
2028	300			750	750		1680						**3480**
2029	1500				750		2460	420					**5130**
2030	1500	900			1500		2460	420					**6780**
2031	1500	3600			1680		2460	420					**9660**
2032	1500	3900			1860		2460	420					**10140**
2033	1500	4110			2430	150	2460	420					**11070**
2034	1500	4320			3000	270	2460	420					**11970**
2035	1800	6030			3600	870	2460	420					**15180**
2036	2400	7830			4590	1470	2460	1920				300	**20970**
2037	2400	7830			5580	1770	2460	2130				300	**22470**
2038	2400	7830			6570	2370	2460	2400				600	**24630**
2039	2400	8040			7560	2670	2460	2400				810	**26340**
2040	2400	8040			8550	3270	2460	2400	1110			1110	**29340**
2041	2400	8040			9570	3270	2460	2400	1650			1110	**30900**
2042	2400	8040			10590	3570	2460	2400	1650			1110	**32220**
2043	2400	8040			11610	3870	2460	2400	1650	300		1410	**34140**
	2400	**8040**		**750**	**11610**	**3870**	**2460**	**2400**	**1650**	**300**		**1410**	**34890**

Capacity Expansion Plan - LG0 (GPC Only)

Incremental

Year	CT w/ SCR	CC	CC w/ CCS	MPC PPA	Solar	Wind	Battery 4-hr (T1)	Battery 4-hr (T2)	Battery 4-hr (T3)	Battery 4-hr (T4)	Medium Duration Storage	Nuclear	Total
2024													
2025													
2026													
2027				750			900						**1650**
2028	300						600						**900**
2029	1200						990	420					**2610**
2030		900			750								**1650**
2031		2700			180								**2880**
2032		300			180								**480**
2033		210			570	330							**1110**
2034		300			570								**870**
2035		1800			600	600							**3000**
2036	600	1500			990	600		900			1200		**5790**
2037					990			270					**1260**
2038					990			840					**1830**
2039	210	210			990	300							**1710**
2040	600				990	300						210	**2100**
2041			30		1020						210	210	**1470**
2042					1020	600						270	**1890**
2043					1020	600					210	270	**2100**
	2910	**7920**	**30**	**750**	**10860**	**3330**	**2490**	**2430**			**1620**	**960**	**33300**

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0388

Cumulative

Year	CT w/ SCR	CC	CC w/ CCS	MPC PPA	Solar	Wind	Battery 4-hr (T1)	Battery 4-hr (T2)	Battery 4-hr (T3)	Battery 4-hr (T4)	Medium Duration Storage	Nuclear	Total
2024													
2025													
2026													
2027				750			900						**1650**
2028	300			750			1500						**2550**
2029	1500						2490	420					**4410**
2030	1500	900			750		2490	420					**6060**
2031	1500	3600			930		2490	420					**8940**
2032	1500	3900			1110		2490	420					**9420**
2033	1500	4110			1680	330	2490	420					**10530**
2034	1500	4410			2250	330	2490	420					**11400**
2035	1500	6210			2850	930	2490	420					**14400**
2036	2100	7710			3840	1530	2490	1320			1200		**20190**
2037	2100	7710			4830	1530	2490	1590			1200		**21450**
2038	2100	7710			5820	1530	2490	2430			1200		**23280**
2039	2310	7920			6810	1830	2490	2430			1200		**24990**
2040	2910	7920			7800	2130	2490	2430			1200	210	**27090**
2041	2910	7920	30		8820	2130	2490	2430			1410	420	**28560**
2042	2910	7920	30		9840	2730	2490	2430			1410	690	**30450**
2043	2910	7920	30		10860	3330	2490	2430			1620	960	**32550**
	2910	**7920**	**30**	**750**	**10860**	**3330**	**2490**	**2430**			**1620**	**960**	**33300**

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Capacity Expansion Plan - HG0 (GPC Only)

Incremental

Year	CT w/ SCR	CC	CC w/ CCS	MPC PPA	Solar	Wind	Battery 4-hr (T1)	Battery 4-hr (T2)	Battery 4-hr (T3)	Battery 4-hr (T4)	Medium Duration Storage	Nuclear	Total
2024													
2025													
2026													
2027				750									**750**
2028					750		600						**1350**
2029							2340	600					**2940**
2030		1050			750								**1800**
2031		2400			180								**2580**
2032		300			180	600							**1080**
2033		210			570	360							**1140**
2034		420			570			210					**1200**
2035		900			600	600		300				300	**2700**
2036	300	2400			990	600		1050			300	300	**5940**
2037					990	510						210	**1710**
2038					990	600		420	210			300	**2520**
2039		210			990	300						210	**1710**
2040					990	600			300			300	**2190**
2041					1020				240				**1260**
2042					1020	600						270	**1890**
2043	240				1020	600						210	**2070**
	540	**7890**		**750**	**11610**	**5370**	**2940**	**2580**	**750**		**300**	**2100**	**34830**

Cumulative

Year	CT w/ SCR	CC	CC w/ CCS	MPC PPA	Solar	Wind	Battery 4-hr (T1)	Battery 4-hr (T2)	Battery 4-hr (T3)	Battery 4-hr (T4)	Medium Duration Storage	Nuclear	Total
2024													
2025													
2026													
2027				750									**750**
2028				750	750		600						**2100**
2029					750		2940	600					**4290**
2030		1050			1500		2940	600					**6090**
2031		3450			1680		2940	600					**8670**
2032		3750			1860	600	2940	600					**9750**
2033		3960			2430	960	2940	600					**10890**
2034		4380			3000	960	2940	810					**12090**
2035		5280			3600	1560	2940	1110				300	**14790**
2036	300	7680			4590	2160	2940	2160			300	600	**20730**
2037	300	7680			5580	2670	2940	2160			300	810	**22440**
2038	300	7680			6570	3270	2940	2580	210		300	1110	**24960**
2039	300	7890			7560	3570	2940	2580	210		300	1320	**26670**
2040	300	7890			8550	4170	2940	2580	510		300	1620	**28860**
2041	300	7890			9570	4170	2940	2580	750		300	1620	**30120**
2042	300	7890			10590	4770	2940	2580	750		300	1890	**32010**
2043	540	7890			11610	5370	2940	2580	750		300	2100	**34080**
	540	**7890**		**750**	**11610**	**5370**	**2940**	**2580**	**750**		**300**	**2100**	**34830**

EXHIBIT GPL-3

0391

Georgia Power Territorial Base Case Load vs. Exist

Year	2024	2025	2026	2027	2028	2029	2030
Peak Demand (MW), (A)	15,268	15,796	16,790	18,163	18,798	19,390	19,966
Owned Generating Capacity (MW), (B)	14,770	15,341	15,343	15,706	15,706	14,702	14,703
Purchased Generating Capacity (MW), (C)	4,535	5,159	5,237	5,321	5,576	5,430	5,430
Dispatchable DSOs (MW), (D)	675	696	716	758	805	750	752
Total Capacity (MW)	19,980	21,196	21,296	21,785	22,088	20,882	20,885
Capacity Required to Meet GPC Target (MW) (E)	(982)	(1,540)	(404)	918	1,411	3,356	4,074
GPC Reserve Margin (%)	30.9%	34.2%	26.8%	19.9%	17.5%	7.7%	4.6%

Notes

(A) Territorial Load requirements less non-dispatchable DSOs

(B) Assumes in-service dates of 7/31/2023 and 4/1/2024, respectively, for Plant Vogt

(C) Includes territorial and imported power purchases. Capacity does not include the

(D) Values stated in combustion turbine equivalence terms

(E) Does not consider planning reserve sharing. Reflects GPC's Target Reserve Mar

Existing Cap

		2024	2025	2026	2027	2028	2029	2030
Owned Generating Capacity (MW)		**14,770**	**15,341**	**15,343**	**15,706**	**15,706**	**14,702**	**14,703**
Nuclear		**2,468**	**2,978**	**2,978**	**2,978**	**2,978**	**2,978**	**2,978**
	HATCH 1	439	439	439	439	439	439	439
	HATCH 2	442	442	442	442	442	442	442
	VOGTLE 1	539	539	539	539	539	539	539
	VOGTLE 2	540	540	540	540	540	540	540
	VOGTLE 3	509	509	509	509	509	509	509
	VOGTLE 4	-	509	509	509	509	509	509
Coal		**4,102**	**4,102**	**4,102**	**4,102**	**4,102**	**3,560**	**3,560**
	BOWEN 1	780	780	780	780	780	780	780
	BOWEN 2	758	758	758	758	758	758	758

ing Capability Budget 2024 MG0_P50 (Winter)

2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043
20,408	20,618	20,818	20,974	21,085	21,198	21,387	21,738	22,105	22,406	22,763	23,124	23,514
14,703	14,703	14,703	14,703	14,013	10,453	10,453	10,494	10,494	10,494	10,494	10,494	10,494
3,411	3,449	3,431	3,465	2,186	1,588	1,548	1,206	1,206	846	826	823	820
750	749	749	749	749	749	749	749	749	749	749	749	749
18,864	18,901	18,883	18,917	16,948	12,790	12,750	12,449	12,449	12,089	12,069	12,066	12,063
6,647	6,873	7,139	7,301	9,409	13,708	13,985	14,724	15,183	15,920	16,386	16,840	17,331
-7.6%	-8.3%	-9.3%	-9.8%	-19.6%	-39.7%	-40.4%	-42.7%	-43.7%	-46.0%	-47.0%	-47.8%	-48.7%

e Units 3 & 4

500 MW Energy Storage System (ESS) Request for Proposals (RFP) approved in the 2022 Integrated Resource Plan (IRP) to show total procurement needs.

gin resulting from a System Target Reserve Margin of 25.50% (2024-2026) and 26% (2027 and beyond).

ability

2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043
14,703	**14,703**	**14,703**	**14,703**	**14,013**	**10,453**	**10,453**	**10,494**	**10,494**	**10,494**	**10,494**	**10,494**	**10,494**
2,978	**2,978**	**2,978**	**2,978**	**2,978**	**2,978**	**2,978**	**2,978**	**2,978**	**2,978**	**2,978**	**2,978**	**2,978**
439	439	439	439	439	439	439	439	439	439	439	439	439
442	442	442	442	442	442	442	442	442	442	442	442	442
539	539	539	539	539	539	539	539	539	539	539	539	539
540	540	540	540	540	540	540	540	540	540	540	540	540
509	509	509	509	509	509	509	509	509	509	509	509	509
509	509	509	509	509	509	509	509	509	509	509	509	509
3,560	**3,560**	**3,560**	**3,560**	**3,560**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
780	780	780	780	780	-	-	-	-	-	-	-	-
758	758	758	758	758	-	-	-	-	-	-	-	-

	BOWEN 3	934	934	934	934	934	934	934
	BOWEN 4	944	944	944	944	944	944	944
	SCHERER 1	72	72	72	72	72	72	72
	SCHERER 2	72	72	72	72	72	72	72
	SCHERER 3	541	541	541	541	541	-	-
	WANSLEY 1	-	-	-	-	-	-	-
	WANSLEY 2	-	-	-	-	-	-	-
Combined Cycle		**4,150**	**4,182**	**4,182**	**4,182**	**4,182**	**4,182**	**4,182**
	MCDONOUGH 4	945	945	945	945	945	945	945
	MCDONOUGH 5	934	934	934	934	934	934	934
	MCDONOUGH 6	894	926	926	926	926	926	926
	MCINTOSH 10	692	692	692	692	692	692	692
	MCINTOSH 11	685	685	685	685	685	685	685
Oil/Gas Steam		**1,108**	**1,108**	**1,108**	**1,108**	**1,108**	**648**	**648**
	GASTON 1 GAS	127	127	127	127	127	-	-
	GASTON 2 GAS	128	128	128	128	128	-	-
	GASTON 3 GAS	102	102	102	102	102	-	-
	GASTON 4 GAS	103	103	103	103	103	-	-
	YATES 6 GAS	323	323	323	323	323	323	323
	YATES 7 GAS	326	326	326	326	326	326	326
Combustion Turbine		**1,880**	**1,880**	**1,880**	**1,880**	**1,880**	**1,870**	**1,870**
	BOULEVARD 1	-	-	-	-	-	-	-
	GASTON A	10	10	10	10	10	-	-
	MCDONOUGH 3A	31	31	31	31	31	31	31
	MCDONOUGH 3B	31	31	31	31	31	31	31
	MCINTOSH 1A	95	95	95	95	95	95	95
	MCINTOSH 2A	95	95	95	95	95	95	95
	MCINTOSH 3A	95	95	95	95	95	95	95
	MCINTOSH 4A	95	95	95	95	95	95	95
	MCINTOSH 5A	95	95	95	95	95	95	95
	MCINTOSH 6A	95	95	95	95	95	95	95
	MCINTOSH 7A	95	95	95	95	95	95	95
	MCINTOSH 8A	95	95	95	95	95	95	95
	MCMANUS 3A	55	55	55	55	55	55	55
	MCMANUS 3B	55	55	55	55	55	55	55
	MCMANUS 3C	55	55	55	55	55	55	55
	MCMANUS 4A	55	55	55	55	55	55	55
	MCMANUS 4B	55	55	55	55	55	55	55
	MCMANUS 4C	55	55	55	55	55	55	55
	MCMANUS 4D	55	55	55	55	55	55	55
	MCMANUS 4E	55	55	55	55	55	55	55
	MCMANUS 4F	55	55	55	55	55	55	55

934	934	934	934	934	-	-	-	-	-	-	-	-
944	944	944	944	944	-	-	-	-	-	-	-	-
72	72	72	72	72	-	-	-	-	-	-	-	-
72	72	72	72	72	-	-	-	-	-	-	-	-
-	-	-	-	-	-	-	-	-	-	-	-	-
-	-	-	-	-	-	-	-	-	-	-	-	-
-	-	-	-	-	-	-	-	-	-	-	-	-
4,182	**4,182**	**4,182**	**4,182**	**4,182**	**4,182**	**4,182**	**4,182**	**4,182**	**4,182**	**4,182**	**4,182**	**4,182**
945	945	945	945	945	945	945	945	945	945	945	945	945
934	934	934	934	934	934	934	934	934	934	934	934	934
926	926	926	926	926	926	926	926	926	926	926	926	926
692	692	692	692	692	692	692	692	692	692	692	692	692
685	685	685	685	685	685	685	685	685	685	685	685	685
648	**648**	**648**	**648**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
-	-	-	-	-	-	-	-	-	-	-	-	-
-	-	-	-	-	-	-	-	-	-	-	-	-
-	-	-	-	-	-	-	-	-	-	-	-	-
-	-	-	-	-	-	-	-	-	-	-	-	-
323	323	323	323	-	-	-	-	-	-	-	-	-
326	326	326	326	-	-	-	-	-	-	-	-	-
1,870	**1,870**	**1,870**	**1,870**	**1,870**	**1,870**	**1,870**	**1,870**	**1,870**	**1,870**	**1,870**	**1,870**	**1,870**
-	-	-	-	-	-	-	-	-	-	-	-	-
-	-	-	-	-	-	-	-	-	-	-	-	-
31	31	31	31	31	31	31	31	31	31	31	31	31
31	31	31	31	31	31	31	31	31	31	31	31	31
95	95	95	95	95	95	95	95	95	95	95	95	95
95	95	95	95	95	95	95	95	95	95	95	95	95
95	95	95	95	95	95	95	95	95	95	95	95	95
95	95	95	95	95	95	95	95	95	95	95	95	95
95	95	95	95	95	95	95	95	95	95	95	95	95
95	95	95	95	95	95	95	95	95	95	95	95	95
95	95	95	95	95	95	95	95	95	95	95	95	95
95	95	95	95	95	95	95	95	95	95	95	95	95
55	55	55	55	55	55	55	55	55	55	55	55	55
55	55	55	55	55	55	55	55	55	55	55	55	55
55	55	55	55	55	55	55	55	55	55	55	55	55
55	55	55	55	55	55	55	55	55	55	55	55	55
55	55	55	55	55	55	55	55	55	55	55	55	55
55	55	55	55	55	55	55	55	55	55	55	55	55
55	55	55	55	55	55	55	55	55	55	55	55	55
55	55	55	55	55	55	55	55	55	55	55	55	55